PD1/bx1 7/20/2020

FILED
07/20/20
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006

E-MAIL RULING SEEKING PARTY COMMENT ON VEHICLE-GRID INTEGRATION ISSUES

Dated July 20, 2020, at San Francisco, California.

/s/ PATRICK DOHERTY
Patrick Doherty
Administrative Law Judge

From: Doherty, Patrick <Patrick.Doherty@cpuc.ca.gov>
Sent: Monday, July 20, 2020 3:23 PM
To: Jamie.Hall@GM.com; jboesel@calstart.org; TGondai@NAAC.org; Joe.Halso@SierraClub.org; CGirouard@AEE.net; SHouston@UCSusa.org; Josh.Cohen@SemaConnect.com; DBowerson@autosinnovate.org; dmccrea1@ford.com; RKing25@Ford.com; Scott.Picco@ul.com; Gavin.gretter@trilliumcng.com; MGoldenKrasner@BiologicalDiversity.org; SGersen@Earthjustice.org; Tom@Greenlots.com; KStainken@PlugInAmerica.org; Paul@Envoythere.com; Jessalyn_Ishigo@AHM.Honda.com; MBaumhefner@nrdc.org; Andrea.Tozer@sce.com; RKMoore@GSwater.com; Josh@ConnCA.com; julie.wiley@sandag.org; Jackie@Nuvve.com; SDAP@sdap.net; Sephra.Ninow@EnergyCenter.org; CFaber@SempraUtilities.com; GBarnes@SempraUtilities.com; aravind.kailas@volvo.com; EWagner@CaliforniaHydrogen.org; MChiacos@CECmail.org; Simon@AmplyPower.com; JWaen@PeninsulaCleanEnergy.com; David.Schlosberg@Enel.com; RKoss@AdamsBroadwell.com; Hilary.Staver@SVCleanEnergy.org; William.Sanders@sfCityAtty.org; Candice.Plotkin@GetCruise.com; ETorres@turn.org; JYLee@Uber.com; Megha.Lakhchaura@EVBox.com; Jennifer@UtilityAdvocates.org; peter@ceaconsulting.com; Christopher.Warner@pge.com; LKoehler@edf.org; NSheriff@Buchalter.com; NSheriff@Buchalter.com; MDay@GoodinMacBride.com; steven@moss.net; Rachelle@ChongLaw.net; chris_king@siemens.com; FWahl@Tesla.com; HGolub@BBKlaw.com; SCampbell@GRIDalternatives.org; MBrandt@ebce.org; CESA_Regulatory@StorageAlliance.org; vgicregulatory@vgicouncil.org; GMorris@emf.net; LeslieA@greenlining.org; SSwaroop@mceCleanEnergy.org; maldridge@ecoact.org; hsickler@svlg.org; SShupe@SonomaCleanPower.org; bweaver@caiso.com; iles@BraunLegal.com; fernandez@braunlegal.com; Fernandez@BraunLegal.com; Fernandez@BraunLegal.com; Michael@CalTransit.org; Trimming, Tovah <Tovah.Trimming@cpuc.ca.gov>; LMH@eslawfirm.com; Joy.Mastache@smud.org; Dan.Marsh@LibertyUtilities.com; rds@dvclaw.com; Sean.Waters@Daimler.com; Ajay.Kumar@PacifiCorp.com; Phil@EVTransportationAlliance.org
Cc: ALJ Docket Office <ALJ_Docket_Office@cpuc.ca.gov>; ALJ Process <alj_process@cpuc.ca.gov>; ALJ_Support ID <alj_supportid@cpuc.ca.gov>
Subject: R.18-12-006: Email Ruling Seeking Party Comment on Vehicle-Grid Integration Issues

Dear members of the R.18-12-006 service list:

This email ruling seeks party comment on issues related to vehicle-grid integration that the Commission must consider by December 31, 2020 pursuant to Public Utilities Code Section 740.16. This email ruling also enters the attached Final Report of the Vehicle-Grid Integration

Working Group and Annexes into the record of this proceeding. Parties are encouraged to utilize the contents of the report and annexes in their comments as appropriate.

Parties are requested to respond to the following questions and file opening comments no later than August 17, 2020. Reply comments are due August 31, 2020. Opening comments shall be limited to 35 pages in length and reply comments shall be limited to 20 pages in length.

1) Should the Commission adopt a revised definition for "electric vehicle grid integration" to replace the definition in Public Utilities Code Section 740.16(b)(1)? If so, what should it be?

2) Which strategies should the Commission adopt by the end of 2020 pursuant to Public Utilities Code Section 740.16(c) to maximize the use of feasible and cost-effective electric vehicle grid integration by January 1, 2030? Parties should explain how each recommended strategy is feasible and cost-effective.

3) For each strategy recommended, what quantifiable metric or metrics should be adopted to measure progress in furthering the strategy under Public Utilities Code Section 740.16(j)?

4) For each strategy recommended, parties should specify how the strategy a) accounts for the effect of time-of-use rates on electricity demand from electric vehicle charging, b) is in the best interests of ratepayers, as defined in Public Utilities Code Section 740.8, and consistent with Public Utilities Code Section 451, c) reflects electrical demand attributable to electric vehicle charging, including from existing approved rates and programs, d) is consistent with the transportation electrification goals described in Public Utilities Code Section 740.12, and e) incorporates the National Institute of Standards and Technology's reliability and cybersecurity protocols, or other equally protective or more protective cybersecurity protocols.

IT IS SO RULED.

The Docket Office shall formally file this ruling.

Patrick Doherty
Administrative Law Judge
California Public Utilities Commission
pd1@cpuc.ca.gov

Attachment A

Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group

June 30, 2020

California Public Utilities Commission
DRIVE OIR Rulemaking (R.18-12-006)

TABLE OF CONTENTS

LIST OF TABLES AND FIGURES

LIST OF ANNEXES (Included in a Separate Document)

Disclaimer: This report does not address every aspect of VGI, but rather provides a starting point for further rulemaking, policy, and programs for VGI by the California Public Utilities Commission and other state agencies and entities. Recognizing that it serves only as a starting point, this report provides a collective expression of the Working Group rather than a record of individual participant positions. In converging on answers, Working Group participants mostly agreed, but the materials, statements, and recommendations do not necessarily represent the statements or recommendations of individual Working Group participants or the stakeholders they represent.

LIST OF ACRONYMS

ADA	Americans with Disabilities Act
AQMD	Air Quality Management District
B2B	Business-to-Business
B2C	Business-to-Consumer
BTM	Behind-the-Meter
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CEC	California Energy Commission
CESA	California Energy Storage Alliance
CPUC	California Public Utilities Commission
DCFC	Direct Current Fast Charger
DER	Distributed Energy Resource
DERP	Distributed Energy Resource Provider
DOE	Department of Energy
DRAM	Demand Response Auction Mechanism
EDU	Electricity Distribution Utility
EE	Energy Efficiency
EPIC	Electric Program Investment Charge Program (CEC)
ESDER	Energy Storage and Distributed Energy Resources Program (CAISO)
EV	Electric Vehicle
EVSE	Electric Vehicle Service Equipment
FERC	Federal Energy Regulatory Commission
FTM	Front-of-the-Meter
GHG	Greenhouse Gas
GRC	General Rate Case
IDER	Integrated Distributed Energy Resources
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-Owned Utility
ISO	Independent Service Operator
kW	Kilowatt
kWh	Kilowatt-hour
LCFS	Low Carbon Fuel Standard
LDV	Light Duty Vehicle
LSE	Load Serving Entity
ME&O	Marketing, Education and Outreach
MHDV	Medium- and Heavy-Duty Vehicle
MUA	Multiple Use Application
MUD	Multi Unit Dwelling
NEC	National Electrical Code
NEM	Net Energy Metering
NGR	Non-Generator Resource
OCPP	Open Charge Point Protocol
OEM	Original Equipment Manufacturer
OIR	Order Instituting Rulemaking
PDR	Proxy Demand Resource
PEV	Plug-in Electric Vehicle
PG&E	Pacific Gas and Electric
PSPS	Public Safety Power Shutoff
PUC	Public Utility Commission
PV	Photovoltaic
RA	Resource Adequacy
RE	Renewable Energy
RFP	Request for Proposals
SB	(California) Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SFH	Single Family Home
SGIP	Self-Generation Incentive Program
TCO	Total Cost of Ownership
TEF	Transportation Electrification Framework
TNC	Transportation Network Companies
TOU	Time-of-Use
UL	Underwriters Laboratories
V1G	EV unidirectional charging
V2G	Vehicle-to-Grid (bidirectional)
V2H	Vehicle-to-Home (bidirectional)
V2M	Vehicle-to-Microgrid (bidirectional)
VGI	Vehicle-Grid Integration

PARTICIPANTS OF THE VGI WORKING GROUP

33North Energy
AEYCH
Alliance for Automotive Innovation
Amazon
Amzur
Argonne National Laboratory
Audi
Auto Alliance
Autos Innovate
Avista
BMW
California Electric Transportation Coalition
California Independent System Operator
CALSTART
California Air Resources Board
California Energy Commission
California Energy Storage Alliance
ChargePoint
Charles Botsford (independent)
Columbia University
California Public Utilities Commission
Daimler
East Bay Community Energy
Electric Auto Association
Electrify America
Enel X
Energy and Environmental Economics
Energy Innovation
ENGIE Impact
EVBox
EVgo
Fermata Energy
Fiat Chrysler
Ford
General Motors
Green Power Institute
Greenlots
Gridworks
Honda
Hubject
Karim Farhat (independent)
Kisensum
Kitu Systems
Los Angeles Department of Water and Power
Lehigh University
Mercedes
Nissan
Natural Resources Defense Council
Nuvve
Olivine
OpenADR Alliance
Pacific Gas and Electric
Paratelic Ventures
Peninsula Clean Energy
Plug-In America
Public Advocates Office
QualityLogic
Resource Insights
Sacramento Municipal Utility District
San Diego Gas & Electric
Santa Clara Valley Transportation Authority
Schatz Energy Research Center
SEI Innovation
Siemens Digital Grid
Small Business Utility Advocates
Smart Cities
SolarEdge
Southern California Edison
Starboard Energy
Strategen
Sumitomo Electric Group
TeMix
Tesla
The Mobility House
ThinkSmartGrid
Toyota
Union of Concerned Scientists
University of California Berkeley
University of California San Diego
University of Delaware
US Department of Energy
US Federal Energy Regulatory Commission
Vehicle-Grid Integration Council
Wallbox
Willdan
WSP

EXECUTIVE SUMMARY

Overview

To realize its vision of a carbon-neutral economy, California has set a target of 5 million zero-emission vehicles on the road and 250,000 charging ports in service by 2030 and has expressed an intent to "reduce costs or mitigate cost increases for all ratepayers due to increased usage of electric vehicles by accelerating electric vehicle grid integration…"[1]

A definition of VGI is codified in California Public Utilities Code Section 740.6:

> "Electric vehicle grid integration" means any method of altering the time, charging level, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle interaction with the electrical grid and provides net benefits to ratepayers by doing any of the following: (a) increasing electrical grid asset utilization; (b) avoiding otherwise necessary distribution infrastructure upgrades; (c) integrating renewable energy resources; (d) Reducing the cost of electricity supply; and (e) offering reliability services consistent with Section 380 or the Independent System Operator tariff.

To help realize these goals and methods, the California Independent System Operator (California ISO), California Energy Commission (CEC), California Air Resources Board (CARB), and California Public Utilities Commission (CPUC) jointly created the Vehicle Grid Integration (VGI) Working Group. A 2019 Ruling of the CPUC tasked the Working Group with addressing the following questions:

(a) What VGI use cases can provide value now, and how can that value be captured?
(b) What policies need to be changed or adopted to allow additional use cases to be deployed in the future?
(c) How does the value of VGI use cases compare to other storage or DER?

The VGI Working Group worked collaboratively between August 2019 and June 2020 to address these three questions. The Working Group was made up of diverse representatives of VGI stakeholders, including state agencies, utilities, community choice aggregators, the California ISO, electric vehicle (EV) manufacturers, battery manufacturers, charging network and energy service providers, advocacy and research groups, industry associations, and ratepayer interest groups. The organization Gridworks was engaged to facilitate the Working Group and create this report of its outcomes and recommendations.

Limits of the Report

The Working Group provided extensive perspectives on PUC Questions (a) and (b). However, due to time, data, and expertise constraints, the Working Group could only suggest ways in which the CPUC might pursue answers to PUC Question (c) in the future. The Working Group also faced limitations in getting private-sector cost information and could only assess costs on a relative basis, precluding cost-benefit analysis or assessment of net value. And the Working Group faced limitations in fully assessing barriers to VGI, including customer interest and acceptance, as well as the costs of eliciting participation in VGI programs, such as marketing and dealership education.

[1] See footnotes in the Introduction for all references and citations.

Why VGI Now?

The Working Group was both mandated and motivated by a conviction that VGI affords many potential benefits, including:

- Accelerating the adoption of EVs by providing additional revenue streams that lower the total cost of vehicle ownership for individual owners and fleet operators
- Reducing costs to electricity ratepayers by reducing congestion on existing power distribution infrastructure and costly distribution system upgrades, as well as reducing the need to invest in new fossil-fuel electricity generation
- Supporting further decarbonization of the electric sector by avoiding curtailment of renewables and providing grid services
- Accelerating reduction of carbon and criteria pollutant emissions in the transportation sector
- Improving grid resiliency and security, including for public safety power shutoff (PSPS) events

Opportunities to realize these benefits are available today and will grow rapidly as EV adoption expands. However, much depends on what happens in the next few years, including shaping electricity customers' attitudes towards VGI as more and more customers purchase EVs.

VGI Use Case Definition and Value

As summarized in Section A of this report, the Working Group first collaborated to develop a VGI use case framework to define, screen, evaluate and prioritize potential VGI use cases. Use cases represent the different ways in which EV charging can be integrated with the grid (or home/local power system) to provide value. Use cases help articulate how value streams can flow to different stakeholders, including EV owners and fleet managers, workplaces and other charging site hosts, charging service providers, utilities and CCAs, ratepayers, and grid operators. Use cases can serve as the building blocks for defining, creating and exchanging value from VGI among these stakeholders, and policy-making should recognize that different use cases may require different policies to help realize these value streams.

The framework developed provides a structuring of the potential VGI market. It recognizes comprehensively the key factors shaping VGI: where the vehicle would be charged/discharged, types of vehicles, services that EV charging can provide, power flow to and/or from the vehicle, control mechanisms for charging or discharging, degree of alignment of actions by the vehicle operator and the charger operator, and the characteristics of charging technologies. The Working Group used this framework to systematically explore the universe of VGI potential and answer the first question before the Working Group, **"what VGI use cases can provide value now?"**

What emerged are 320 different VGI use cases that, for the purposes of this report, should be considered as able to provide value by 2022. These use cases address VGI across a wide range of sectors (e.g., residential, commercial, rideshare, and fleets), applications (e.g., for customer bill management, renewable energy integration, or distribution upgrade deferral), approaches to control charging and/or discharging (direct and indirect), and types of charging (V1G and V2G). Both light-duty vehicles (i.e., passenger and ride-share vehicles) and medium- and heavy-duty vehicles (i.e., trucks, buses, and vans) are represented by the use cases.

However, the value perceived by Working Group participants for these use cases varied widely on a broad spectrum. Therefore, it is clear that these 320 use cases should not all be treated equally in policy-making, but should be differentiated across a spectrum of value. Furthermore, many other use cases developed by the Working Group have the potential to provide value in the medium- and long-term.

Answers to the question of how to capture the value of these use cases are addressed by the policy recommendations in Section B of this report.

Defining Key Terminology

V1G is single-direction charging that allows managed charging and flexible demand ("demand response")

V2G (vehicle-to-grid) is bidirectional charging and discharging, allowing vehicles to discharge stored energy back onto the grid or into a building or local power system.

Indirect (passive) control of charging involves adjusting the EV charge/discharge based on time-varying price signals or grid conditions. Charging behavior in response to such signals is not prescribed or commanded, and can occur passively without any response required by an individual customer.

Direct (active) control of charging involves adjusting the EV charge/discharge in response to active external "dispatching instructions" that prescribe or command charging behavior. EV participation in the Demand Response Auction Mechanism (DRAM) would be a good example of active aggregated charging.

<u>Differentiating Among Use Cases</u>

Although the Working Group did not conduct cost-benefit analysis nor rank these use cases explicitly, it did consider several ways to differentiate use cases that were scored highly by the Working Group in terms of benefits, costs, and ease/risk of implementation. Such highly-scored use cases illustrate different aspects of value. However, the Working Group could not differentiate among use cases using cost-effectiveness or net value.

One key differentiator among these potential use cases is the benefits they provide through their applications and control approaches. Many use cases scored highly by the Working Group related to:

- Customer bill management
- Avoiding or deferring investment in upgrading the power distribution grid
- Home and building backup power and resiliency
- Daytime charging to support balancing and storing renewable energy
- Indirect (passive) control approaches, such as time-varying retail rates and responding to informational signals of grid conditions (i.e., carbon signals or real-time wholesale energy prices) that do not require specific customer behavioral responses

The total statewide benefit from a single use case ranged up to an estimated $200 million per year based on scoring of the use cases by Working Group participants (see Section A for scoring details).

While the Working Group recognized the challenge of simultaneously advancing 320 use cases, ***an important result is that there are many potential VGI use cases that can provide value, and that the potential market for VGI solutions is diverse and interwoven across a broad swath of the transportation and power sectors.*** Given the use case assessment work performed by the Working Group, it appears that the work of developing markets for VGI solutions will demand persistent action for the next several years. ***California should take an inclusive and collaborative approach to VGI opportunities given the evolving nature of the regulatory and market landscape.***

Focus on V2G and on Medium- and Heavy-Duty Vehicles

There are several key ways to differentiate use cases within the VGI landscape that give shape to the Working Group's policy recommendations, including V2G as distinct from V1G, medium- and heavy-duty as distinct from light-duty. Light-duty V1G use-cases such as residential customers charging at single-family homes on time-varying rates are generally more familiar. The Working Group made a conscious effort to explore and promote medium- and heavy-duty and V2G use cases. Through this effort the Working Group recognized the benefits unique to these use cases and emphasized recommendations to overcome barriers for them.

Policy Recommendations

The Working Group built off its successful definition and valuation of VGI use cases to consider the second question before the Working Group, **"what policies need to be changed or adopted to allow additional use cases to be deployed in the future?"** The overriding intent of this process was to create actionable specific recommendations for consideration by California's state agencies, investor-owned utilities, community choice aggregators, the California ISO, and others.

As summarized in Section B of this report, the Working Group developed a set of 92 individual recommendations for policy actions that California state agencies, utilities, community choice aggregators, and CAISO could undertake to advance VGI in the short-term (2020-2022), medium-term (2023-2025), and long-term (2026-2030). These recommendations are separated into 11 different policy categories. Together, these 11 categories broadly address virtually all aspects of policy support for the VGI use cases:

#	Category
1	Reform retail rates
2	Develop and fund government and LSE customer programs, incentives, and DER procurements
3	Design wholesale market rules and access
4	Understand and transform VGI markets by funding and launching data programs, studies and task forces
5	Accelerate use of EVs for bi-directional non-grid-export power and PSPS resiliency and backup
6	Develop EV bi-directional grid-export power including interconnection rules
7	Fund and launch demonstrations and other activities to accelerate and validate commercialization
8	Develop, approve, and support adoption of technical standards not related to interconnection
9	Fund and launch market education & coordination
10	Enhance coordination and consistency between agencies and state goals
11	Conduct other non-VGI-specific programs and activities to increase EV adoption

Of the 92 policy recommendations made by the Working Group, the following 23 constitute the most urgent recommendations with the strongest level of agreement by a majority of participants:

Category	Policy Recommendations (*)
1	Create an "EV fleet" commercial rate that allows commercial and industrial customers to switch from a monthly demand charge to a more dynamic rate structure
2	Require utilities to broadcast signals to a DER marketplace of qualified vendors (curtailment and load) V2G systems become eligible for some form of SGIP incentives Enable customers to elect BTM load balancing option to avoid primary or secondary upgrades, either if residential R15/16 exemption goes away, or as an option for non-residential customers Consider coordinated utility and CCA incentives for EVs, solar PV, inverters, battery storage, capacity, and EV charging infrastructure to support resilience efforts in communities impacted by PSPS events Allow V1G and V2G to qualify for SGIP to level the playing field with incentives for other DERs, but V1G would get less incentive compared to V2G based on permanent load shift logic Incentive(s) for construction projects with coincident grid interconnection and EV infrastructure upgrade Enable customers, via Rules 15/16 or any new EV tariff, to employ load management technologies to avoid distribution upgrades, and focus capacity assessments on the Point of Common Coupling
4	Use EPIC, ratepayer, US DOE, and/or utility LCFS funds for an on-going, multi-year program to convene VGI data experts to study lessons learned, quantify VGI/DER net value, fund new data sources, and address other topics
5	Pilot funding for EV backup power to customers not on microgrids, including state-wide goals for at least 100 EVs by 2021 and 500 EVs by 2022; utilities to consider the feasibility of EVs for emergency backup generation in PSPS plans and resiliency solutions
6	Pilot funding for V1G and V2G for microgrid and V2M solutions, including a state-wide near-term goal; and utilities' PSPS plans and microgrid frameworks should consider EVs for FTM grid services
7	Focusing on resiliency and backup application in workplace and multi-unit dwellings, leverage EPIC funding to pilot use-cases to understand and reduce costs and to streamline implementation. Create pilots to demonstrate V2G's ability to provide the same energy storage services as stationary systems and let V2G systems participate in pilots for stationary storage Special programs and pilots for municipal fleets to pilot V2G as mobile resiliency Demonstration to define the means to allow aggregators, EV network providers, and charge station operators to dynamically map the capacity and availability of EVSE resources, using open standards Use EPIC, ratepayer, USDOE, and/or utility LCFS funds ($50M) in many competitively bid large-scale demonstrations of promising VGI use cases to provide data needed to scale up VGI efforts (e.g., validate consumer acceptance, incentive levels, security, net value, and communication pathways) Study to understand the impact on the distribution grid and generation system from EVs based on over ten existing/planned mandates from CARB & AQMDs to meet California 2045 carbon neutral goal
9	Create public awareness and education programs and materials on V2G systems and how to get them. This could particularly be focused toward government fleets Optimize CALGreen codes for VGI and revise to require more PEV-ready parking spaces and expand to existing buildings
10	State agencies coordinate and maintain consistency on TE and VGI across the different policy forums with no duplication of regulation, clear roles and vision on VGI and priority on state TE goals over VGI Incentivize use of multiple open standards for VGI communication, charging networks, cloud aggregators, and site hosts
11	Streamline permitting for charging infrastructure Create Incentives for charging infrastructure for new public parking lot construction projects

(*) This table is based on Table 9 in Section B, "Short-Term Policy Recommendations with Strong Agreement."

These policy recommendations, along with the many others also described in this report and supported by participants, reflect the strength and diversity of the Working Group's recommendations on:

- V1G and V2G
- Light-, medium-, and heavy-duty vehicles
- Short-, medium-, and long-term
- Actions needed by individual agencies or LSEs and those requiring collaboration across jurisdictions

Section B gives a full account of all policy recommendations, as well as valuable dissenting perspectives. Annex 1 provides links to the full set of materials developed by the Working Group, which include extensive additional information on the policy recommendations, such as full descriptions, further comments, metrics, strategies, lead and supporting agencies/entities, barriers, and relevant use cases.

Valuing VGI Relative to Other Distributed Energy Resources

The Working Group was challenged by the third question, "**how does the value of VGI use cases compare to other storage or DERs?**" and does not offer a complete response at this time. Challenges included:

- Limited insight into the costs of VGI resources and limited availability of cost data
- Limited expertise by many participants in storage and other DERs
- Lack of time and resources to conduct the necessary quantitative analytics and literature reviews
- Lack of a developed framework and analysis criteria to make true "apples-to-apples" comparisons

While the Working Group could not respond in full, Section C of this report contributes substantially to resolving this question by organizing the challenges and potential approaches to achieving resolution. Further efforts to compare VGI use cases with other DERs can recognize and incorporate the wealth of work and perspectives on VGI use cases produced by the Working Group.

Next Steps

The VGI Working Group is proud to present this report and associated materials. Working Group participants were motivated by a conviction that VGI affords many potential benefits. Many opportunities to realize these benefits are available today and will grow rapidly as EV adoption expands, as shown by the extensive work completed by the Working Group on use case assessment and policy recommendations. This work provides a solid foundation for the next stages of VGI in California, and the Conclusion section of this report provides a number of clear next steps.

The high degree of cooperation and collaboration achieved among 85 participating organizations and individuals during the ten-month course of the Working Group also demonstrates that VGI is a unique and effective convening umbrella or venue for fostering collaboration between the electric power and EV/charging sectors, and among many types of industry, government, advocacy, research, and utility and CCA stakeholders.

The VGI Working Group, consisting of participants voluntarily contributing their limited time and resources, commends this report to the leaders of the California ISO, CEC, CARB, and CPUC. We ask for thoughtful consideration of these recommendations and a timely response to this plea.

INTRODUCTION

To realize its vision of a carbon-free economy, California has set a target of 5 million zero-emission vehicles on the road and 250,000 charging ports in service by 2030.[2] California has also expressed an intent to "reduce costs or mitigate cost increases for all ratepayers due to increased usage of electric vehicles by accelerating electric vehicle grid integration."[3] Today California already leads the nation in electric vehicle (EV) adoption with over 700,000 EVs on the road.[4]

Fueling millions of EVs is both a challenge and an opportunity for California's grid and customers. The California Independent System Operator (California ISO), California Energy Commission (CEC), California Air Resources Board (CARB), and California Public Utilities Commission (CPUC), along with other state agencies and organizations, have each invested significant effort to investigate how EVs can be best integrated with the electric grid.[5]

One key focus of California state agencies has been to understand how to integrate incremental electric vehicle load in a way that creates value to the grid, to utilities, and to customers, and identify strategies to capture and scale that value. If charging occurs during existing peak periods, California may (1) need to invest in new distribution infrastructure and generation, (2) face new grid operational challenges, and (3) see increased emissions from the electric sector.[6] Conversely, charging behavior that avoids peak periods in favor of times that are optimal to both the customer and the grid presents an opportunity. If EV load can be managed or vehicles can be configured to export power to the grid, new investment, operational challenges and emissions increases can be avoided, all while reducing emissions from the transportation sector and providing new, more affordable mobility.

There are also challenges and opportunities for EVs in the context of wildfire risk and California's Public Safety Power Shutoffs (PSPS). Some customers may be hesitant to adopt EVs for fear that charging during an outage would be impossible. Other customers may see an opportunity, using Vehicle-to-Building (V2B) technology to provide onsite backup power or Vehicle-to-Grid (V2G) options to support grid resilience.

Opportunities for integrating EVs with the grid have collectively been called Vehicle Grid Integration (VGI). California's Public Utilities Code Section 740.16 defines VGI as follows: [7]

> "Electric vehicle grid integration" means any method of altering the time, charging level, or location at which grid-connected electric vehicles charge or discharge, in a manner that optimizes plug-in electric vehicle interaction with the electrical grid and provides net benefits to ratepayers by doing any of the following: (a) Increasing electrical grid asset utilization; (b) Avoiding otherwise necessary distribution infrastructure upgrades; (c) Integrating renewable

---

[2] Executive Order B-48-18; https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html
[3] California Public Utilities Code Section 740.6 (a)(D)(2)
[4] https://www.veloz.org/wp-content/uploads/2020/02/12_Q4_2019_Dashboard_PEV_Sales_veloz.pdf
[5] https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf; https://www.cpuc.ca.gov/vgi/; https://www.energy.ca.gov/programs-and-topics/programs/california-vehicle-grid-integration-roadmap-update
[6] Vehicle-Grid Integration Initiative 4/12/19; https://gridworks.org/wp-content/uploads/2019/05/VGI_4.12-Slides.pdf
[7] California's Public Utilities Code Section 740.16; https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB983

energy resources; (d) Reducing the cost of electricity supply; (E) Offering reliability services consistent with Section 380 or the Independent System Operator tariff" [8]

VGI can include a range of solutions, from passive interventions such as time-varying (or time-of-use) electricity rates that give customers pricing signals to incentivize or disincentivize charging during specific time windows, to active solutions that leverage the EV's battery to modulate the vehicle's charge or discharge into the grid. VGI has the potential to provide a wide range of benefits for the adopting customers, electricity ratepayers, their electricity service providers, grid operators, and the overall environment and society.

Scoping of the VGI Working Group

As part of California's continuing policy-making efforts for accelerating the adoption of EVs and for realizing the multiple benefits of EVs, the CPUC instituted in 2018 an Order Instituting Rulemaking (OIR) to Continue the Development of Rates and Infrastructure for Vehicle Electrification (R.18-12-006), also called the "DRIVE OIR."[9] An associated May 2, 2019 Scoping Ruling and Memo ordered a new interagency, multi-stakeholder VGI Working Group to focus on identifying the costs and benefits of VGI use cases, tied to the goals set forth in the 2018 OIR.[10]

The Working Group was scoped to evaluate use cases for direct and indirect managed charging, including use cases for single-direction charging for responding to time-varying rates and dispatched demand-response (commonly referred to as V1G), bidirectional use cases in which vehicle batteries can discharge stored energy back onto the grid (vehicle-to-grid or V2G), and bidirectional use cases in which vehicle batteries discharge only behind-the-meter (vehicle-to-building/home or V2B/V2H).[11] As directed in the R.18-12-006 Scoping Ruling, the Working Group was to, at a minimum, cover the following questions:

(a) What VGI use cases can provide value now, and how can that value be captured?
(b) What policies need to be changed or adopted to allow additional use cases to be deployed in the future?
(c) How does the value of VGI use cases compare to other storage or DER?

The Working Group collaborated between August 19, 2019 and June 30, 2020 developing, discussing, and converging on answers to these three questions (henceforth called "PUC Questions"). Over 85 organizations and individuals actively participated, including state agencies, investor-owned utilities (IOUs), community choice aggregators (CCAs), municipally owned utilities (MOUs), the California ISO, EV manufacturers, battery manufacturers, charging network and energy service providers, advocacy groups, industry associations, research and academic institutions, and ratepayer interest groups. This

---

[8] SB 676; http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB676

[9] R.18-12-006 Development of Rates and Infrastructure for Vehicle Electrification and Closing OIR; https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=252025566; this rulemaking followed a 2017 "VGI Communications Protocol Working Group" as noted in the DRIVE OIR, during which parties requested that the working group process be continued, leading to the present Joint Agencies VGI Working Group scoped in the DRIVE OIR.

[10] May 2, 2019 Scoping Ruling and Memo; https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K712/285712622.PDF

[11] Ibid. Managed charging is defined here as a coordinated shift/modulation of the time or level of EV charging or discharging in response to a variety of possible external signals, either passively or actively. Other literature may take a narrower view of the meaning of managed charging, such as limiting it to direct (active) control only.

level of participation, expertise, and perspectives was fundamental to the success of the Working Group. The organization Gridworks, an experienced facilitator on VGI and DERs more broadly in California and elsewhere, facilitated the process.

Participants contributed through a regular series of workshops, conference calls, submissions of materials, and reviews. A broad range of experts and stakeholders conducted use case assessment, including group-based and individual-based use-case screening and scoring, developed policy recommendations, and took part in an extended survey on the policy recommendations. All together this generated hundreds of recommendations and tens of thousands of individual data points on participant assessments, opinions, and comments.

Community Choice Aggregation and VGI

Community Choice Aggregators (CCAs) participated actively in the Working Group, supporting the creation of recommendations for all Load Serving Entities (LSEs). As nonprofit public entities governed by the cities, counties and towns that they serve, CCAs now represent a large driver of clean energy in California. As electricity suppliers to public sector, residential, business and industry customers, CCAs possess relevant customer data and are using that data to inform programs for transportation electrification. As CCAs continue to expand their transportation electrification programs, coordination and planning between CCAs and IOUs on VGI will be essential.

Limits of the Report

The Working Group provided extensive perspective on PUC Questions (a) and (b). However, due to time, data, and expertise constraints, the Working Group could only suggest ways in which the CPUC might pursue answers to PUC Question (c) in the future.

This report does not address every aspect of VGI, but rather provides a starting point for further rulemaking, policy, and programs for VGI by the CPUC and other state agencies. Recognizing that it serves only as a starting point, this report provides a collective expression of the Working Group rather than a record of individual participant positions. In converging on answers, Working Group participants mostly agreed, but the materials, statements, and recommendations do not necessarily represent the statements or recommendations of individual Working Group participants or the stakeholders they represent.

While focusing on the three PUC Questions, the Working Group deemed some issues out of scope or beyond its ability and time to address, including: net-benefit analysis that directly compares benefits to costs; realistic detailed cost data on use cases; comprehensive treatment of barriers to VGI; and customer acquisition expenses and outreach needed to get customers to participate in VGI programs (e.g., incentives, marketing, dealership education).

Stages of the Working Group and Connection to Other VGI Efforts

Over the ten-month period the Working Group proceeded in four distinct stages (Table 1). The materials produced by the Working Group over these four stages are mapped and linked in Annex 1. The process through which the Working Group developed these materials is described in Annex 2. And further reference material is provided in Annex 3. In addition to answering PUC Questions (a) and (b), the Working Group produced a great wealth of materials containing recommendations, comments, frameworks, and perspectives on VGI for the short-, medium-, and long-term.

The VGI Working Group conducted its work with the full recognition of the many other ongoing and planned efforts by California state agencies and other entities to address transportation electrification.[12] These include the new mandates of California Senate Bill (SB) 676 for supporting transportation electrification to 2030[13], the Transportation Electrification Framework[14], an updated CEC VGI Roadmap in progress[15], CALGreen building code updates[16], SGIP program revisions[17], the Rule 21 interconnection proceeding[18], the microgrids proceeding[19], CPUC rates proceedings[20], CEC EPIC funding[21], and many initiatives by private entities, IOUs, CCAs, and other Load Serving Entities (LSEs).

Table 1: Four Stages of the VGI Working Group

Stage	Dates	Materials Produced
1. Methodology	8/19/19-10/31/19	Developed and agreed upon a basic use case assessment framework and methodology that defines over 2500 potential VGI use cases.
2. Use case assessment: PUC Question (a)	9/30/19-1/30/20	Identified and screened 1060 distinct use cases that could potentially provide value, using screens for technological feasibility, market maturity, customer acceptance and adoption, and data availability. Scored use cases that passed screening in terms of benefits, costs, and ease/risk of implementation. Identified over 300 use cases deemed to provide value in the short-term to 2022, and many additional use cases that could potentially provide value in the medium- and long-term.
3. Policy recommendations: PUC Question (b)	1/31/20-6/4/20	Developed and consolidated policy recommendations into a set of 92 discrete recommendations in 11 categories with extended supporting descriptions and accompanying state agency and CAISO comments. Then surveyed participants on their agreement with these recommendations, the clarity and relevance of the recommendations, and further written comments, receiving over 9,000 survey datapoints.
4. DER comparisons: PUC Question (c)	4/16/20-5/15/20	Suggested further action by the PUC in comparing VGI use cases with other DER use cases, but did not provide an answer to PUC Question (c).

[12] Among the materials generated by the Working Group were "stock-takes" of existing efforts by state agencies, the California ISO, and CCAs; see links in Annex 1.
[13] SB676 ; https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB676
[14] SB 350 Transportation Electrification Programs; https://www.cpuc.ca.gov/sb350te/, (D.18-05-040); https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457637
[15] CEC VGI Roadmap; https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-MISC-04
[16] CALGreen (CCR, Title 24, Part 11); https://www.dgs.ca.gov/BSC/Resources/Page-Content/Building-Standards-Commission-Resources-List-Folder/CALGreen
[17] SGIP; https://www.cpuc.ca.gov/sgip/
[18] Rule 21 Interconnection Proceeding (R.17-07-007); https://www.cpuc.ca.gov/Rule21/
[19] Microgrids OIR (19-09-009); https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M314/K274/314274617.PDF
[20] Zero Emission Vehicle Rate Programs; https://www.cpuc.ca.gov/General.aspx?id=12184
[21] CEC Electric Program Investment Charge Program; https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program

Why Is VGI Important?

At the end of the Working Group, participants were asked why they had participated and why they thought that effort on VGI was worthwhile. Some responses were:

> VGI can provide key, material benefits to the EV driver: from financial incentives/rewards that help to lower the total cost of ownership, to confidence and assurance that their charging needs will be taken into account across all charging venues, to helping align their EV charging with renewable availability (appeals to the 'green' conscience). In this way, we see VGI as a key element in helping to enable and accelerate EV adoption. –Ford
>
> Intelligently marrying electric vehicles and the grid offers a significant opportunity to unlock value and benefits for EV drivers, ratepayers, industry stakeholders, and society overall. –General Motors
>
> VGI allows us to maximize the value of our EV charging technologies we are able to deliver to drivers, site hosts, utilities, and grid operators. –Enel X
>
> VGI is an integral part of ensuring that transportation electrification is clean, affordable, resilient, and simple. VGI should be proactively and thoughtfully included in transportation electrification strategies, plans, programs, and projects. VGI is also a key venue for automakers, utilities, charging providers, and others to come together to ensure a successful transition to the mobility future we seek. –ENGIE Impact
>
> Our interest lies in developing the electric transportation market. We want to do everything possible to reduce barriers to adoption during its growth phase. Through VGI, both the EV driving public and ratepayers will ultimately benefit. –Southern California Edison

The Working Group took note of the many benefits that VGI can provide. The comments above point to benefits that can include lowering total ownership costs for EV owners and fleet operators by providing additional revenue streams; reducing costs to electric ratepayers by limiting congestion on existing distribution infrastructure, the need for new fossil generation resources, and costly distribution system upgrades; supporting further decarbonization of the electric sector by avoiding curtailment of renewables and providing grid services; and accelerating reduction of carbon and criteria pollutant emissions from the transportation sector. Many other potential benefits are explained in Working Group materials and referenced literature provided in Annexes 1 and 3.

The Working Group also noted the ubiquitous nature of VGI potential across all customers and businesses, given the acceleration of EV adoption, and the unique role of VGI in fostering EV adoption. That is, VGI can reduce the total cost of ownership of electric vehicles, unlock new value propositions and revenue streams, and facilitate charging infrastructure investments. VGI-enabled EVs can also provide grid reliability services and help limit overall electricity system cost increases by providing lower-cost alternatives to traditional supply-side resources, and by mitigating the cost impacts of rising EV and renewable energy adoption.

And the Working Group also took note of several potentially unique attributes of VGI that can distinguish VGI from other traditional DERs and also provide complementary benefits to traditional DERs, although further understanding and experience is needed to confirm these attributes:[22]

- **Ubiquity.** EVs will become ubiquitous so applications and benefits can apply to a broad segment of utility customers, workplaces, and destinations.
- **Simplicity.** For at least some use cases, load flexibility via VGI may be relatively simple to implement, for example a smart charger that responds to time-varying price signals.
- **Fast and flexible response.** Charging may be able to respond quickly to event or price signals to provide high-capacity real-time flexibility for serving grid needs such as balancing renewable energy intermittency and supporting intra-day ramping.
- **Load shift capacity.** Residential charging represents long-duration loads that are generally quite able to shift given how long cars are parked and be responsive to TOU rates.
- **Leveraging of EV investments.** Investment in EVs themselves yields clean transportation benefits independent of VGI. VGI solutions can be incremental or additional in leveraging existing or planned investments in EVs and charging infrastructure.
- **Multiple benefit streams.** There is also the potential for "value stacking" in which multiple benefits or applications can be accrued simultaneously or at different times of day, so that there are multiple potential value streams from a single investment.
- **Resiliency.** There are unique resiliency benefits, at both the building-level and community-level, to counteract Public Safety Power Shutoffs (PSPS).
- **Locational flexibility.** EVs can respond to location-specific grid needs, as EVs in different locations can flexibly offer charging or discharging resources to the grid.
- **Cross-industry collaboration.** VGI is also a unique and effective convening umbrella or venue for fostering collaboration among entities in the electric power and EV/charging industries.

Senate Bill 676 and the VGI Working Group

During the course of the Working Group, Senate Bill (SB) 676 was enacted by the California legislature. SB 676 adds a new section 740.16 to the Public Utilities Code on the subject of transportation electrification. With the passage of SB 676, the CPUC, CEC, and other state agencies assumed further responsibilities with regard to charting and developing VGI policy in California to 2030. Per SB 676, "the commission shall establish strategies and quantifiable metrics to maximize the use of feasible and cost-effective electric vehicle grid integration by January 1, 2030."[23]

Although the scope of the VGI Working Group did not change in response to the passage of SB 676, the broad mandate of PUC Question (b) on policy recommendations allowed the Working Group to think longer term to 2030. The use cases identified by the Working Group are also relevant to the longer-term. The use case assessments described in Section A and the policy recommendations described in Section B should be considered by the CPUC as it provides guidance for California's regulated utilities to comply with the VGI requirements established in Public Utilities Code section 740.16.

[22] These bullets stem from a "targeted discussion" of the Working Group, but were not substantiated with data nor endorsed by the full Working Group as currently presented.
[23] SB 676; http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB676

SECTION A. PUC QUESTION (A): WHAT VGI USE CASES CAN PROVIDE VALUE NOW, AND HOW CAN THAT VALUE BE CAPTURED?

Use cases represent the different ways in which EV charging can be integrated with the grid (or home/local power system) to provide value. Use cases help articulate how value streams can flow to different stakeholders, including EV owners and fleet managers, workplaces and other charging site hosts, charging service providers, utilities and CCAs, ratepayers, and grid operators. Use cases can serve as the building blocks for defining, creating and exchanging value from VGI among these stakeholders, and policy-making should recognize that different use cases may require different policies to help realize these value streams.

The Working Group put forth 320 use cases which, for the purposes of this report, should be considered as "able to provide value now."[24] These use cases are given in Annex 5. Most Working Group participants agreed that no scored use case should be excluded from being considered as "able to provide value now," since all use cases that passed screening and received a benefit score indicated at least some value.[25]

However, the value perceived by Working Group participants for these use cases varied widely on a broad spectrum, when benefits, costs, and the ease and riskiness of implementation (related to barriers and many other factors) are taken into account. Therefore, it is clear that these 320 use cases should not all be treated equally in policy-making, but should be differentiated across a spectrum of value. Furthermore, many other use cases developed by the Working Group beyond these 320 use cases have the potential to provide value in the medium- and long-term.

Although the Working Group did not prioritize or rank these use cases explicitly, it also put forth a number of smaller groupings of these 320 use cases ("subsets") that were scored highly by the Working Group in terms of benefits, costs, and ease/risk of implementation. And although the Working Group did not choose any single one of these subsets to recommend above any other, the subsets nevertheless show different aspects of value and present a robust overview. Most Working Group participants also agreed that the answer to "how can that value be captured" is answered by the policy recommendations put forth in Section B, also considering the specific use cases to which a given policy could apply.

In order to assess use case value and answer PUC Question (a), one of the first tasks of the Working Group was to define and adopt a framework and methodology for assessing VGI use cases. The dimensions of the framework were purposely defined to be of most relevance to policy making, capturing those aspects of use cases that can be connected to, or are supported by, particular policy

---

[24] The 320 use cases are those receiving at least at least a partial benefit score from the scoring process described later in this section. This means that at least one participant scored the use case for benefits, either for the $/EV/year benefit metric, and/or for the metric total population of EVs that could participate by 2022. There was some debate about whether use cases scored on only one of these metrics be excluded, since the full benefit of multiplying the two metrics together could not be obtained, most participants agreed to include the use case if only one of these metrics was scored. Also, the conclusion that all use cases with benefits should, for the purposes of this report, be considered as "able provide value now" should only be interpreted as an answer to PUC Question (a), and does not imply that programs to enable these use cases necessarily maximize benefits and minimize costs.

[25] The conclusion that all use cases with benefits should, for the purposes of this report, be considered as "able to provide value now" should only be interpreted as an answer to PUC Question (a), and does not imply that programs to enable these use cases necessarily maximize benefits and minimize costs.

strategies. The framework also provides a foundation for connecting use cases to specific business models, although the Working Group in assessing use case value for PUC Question (a) did not consider business models associated with use cases.

The framework adopted by the Working Group consists of six dimensions for characterizing a use case. These are:

1. Sector. The Sector pinpoints where the vehicle is used and charged/discharged. It could be broadly grouped into residential and commercial categories, or subsets thereof (e.g. commercial school bus, or commercial public destination). The Working Group decided to employ 13 options for Sector.

2. Application. The Application refers to the service(s) VGI aims to provide. Applications can be broadly grouped into "customer applications" that focus on services to the electricity customer and/or EV owner/operator, and "system applications" that focus on services to the grid. While the prospect of "stacking" applications and their values is important, such that multiple applications and services can be delivered, the framework clarifies that "customer applications" and "system applications" should be treated separately and not stacked. The Working Group decided to employ 17 options for Application.

3. Type. The Type determines the power flow to and/or from the vehicle, whether uni-directional (V1G) or bi-directional (V2G). In this framework, "V2G" represents all bidirectional types including power flow exporting from the vehicle that may not reach the grid, such as for non-export "vehicle-to-home" (V2H) and "vehicle-to-building" (V2B) use cases.

4. Approach. Approach refers to the mechanism through which the vehicle's charge and/or discharge is controlled. Approach can be either indirect (passive) control or direct (active) control:

- Indirect (passive) control of charging involves adjusting the EV charge/discharge based on time-varying retail price signals or signals of grid conditions (i.e., carbon signals or real-time wholesale prices). Charging behavior in response to such signals is not prescribed or commanded, and can occur passively without any active response required by an individual customer.

- Direct (active) control of charging involves adjusting the EV charge/discharge in response to active external "dispatching instructions" that prescribe or command charging behavior. Aggregated charging and demand-response programs are good examples. The instructions may directly command charging behavior or may prescribe how to respond to other received signals such as time-varying prices or grid conditions.

5. Resource Alignment. Resource Alignment specifies whether the "EV actor" and the "EVSE actor" are "unified" meaning both the EV and EVSE are controlled and/or operated by the same actor, or "fragmented" meaning controlled and/or operated by different actors. If they are fragmented, then Resource Alignment further specifies whether the separate actors are "aligned" or not, meaning whether their intentions and incentives coincide or are different. Fragmented and misaligned use cases present the greatest potential for barriers. The "EV actor" is the party that controls and/or operates the electric vehicle, and "EVSE actor" is the party that controls and/or operates the electric vehicle charger under the utility meter. There are three logical options for Resource Alignment, shown in Table 2.

6. Technology. Technology identifies the hardware and software needed to realize the VGI opportunity. Technology considerations include, but are not limited to electric vehicle type, charging rate, charging type (e.g. AC with mobile inverter, DC with stationary inverter), and communication requirements and pathways to EV and/or EVSE.

For each of the first five dimensions, the Working Group defined a specific set of options that could be chosen to define a given use case (Table 2).

Table 2. Dimensions of the Use Case Assessment Framework and Use-Case-Definition Options

Sector	Application	Type	Approach	Resource Alignment
Residential-Single-Family Home	Customer-Bill Management	V1G	Indirect (passive)	Unified and Aligned
Residential-Single-Family Home, Rideshare	Customer-Upgrade Deferral	V2G	Direct (active)	Fragmented and Aligned
Residential-Multi-Unit Dwelling	Customer-Backup, Resiliency			Fragmented and Misaligned
Residential-Multi-Unit Dwelling Rideshare	Customer-Renewable Self-Consumption			
Commercial-Workplace	System-Grid Upgrade Deferral			
Commercial-Public, Destination	System-Backup, Resiliency			
Commercial-Public, Destination Rideshare	System-Voltage Support			
Commercial-Public, Commute	System-Day-Ahead Energy			
Commercial-Public, Commute Rideshare	System-Real-Time Energy			
Commercial-Fleet, Transit Bus	System-Renewable Integration			
Commercial-Fleet, School Bus	System-GHG Reduction			
Commercial-Fleet, Small Truck (class 3-5)	System-RA, System Capacity			
Commercial-Fleet, Large Truck (class 6-8)	System-RA, Flex Capacity			
	System-RA, Local Capacity			
	System-Frequency Regulation Up/Down			
	System-Spinning Reserve			
	System-Non-Spinning Reserve			

For the sixth (technology) dimension, for medium-duty and heavy-duty vehicles (MHDV), the sector dimension covered the basic vehicle type -- large truck (class 6-8), small truck (class 2-5), airport shuttle bus, school bus, short-range transit bus, long-range transit bus, and transit shuttle van. However, the Working Group recognized that these four sectors needed to be further delineated for use case development and screening, given the multitude of potential MHDV vehicle and service types. Thus, the Working Group extended the technology dimension for MHDV to include the sub-type of vehicle and the type of service for which it is employed. That is, trucks and buses were optionally delineated into several specific technology variants by battery capacity, charger power, duty cycle, average mileage per route, daytime vs. nighttime charging, and other technology notes. This resulted in a number of discrete technology options (such as “Large Truck A”) when defining MHDV use cases. The MHDV sectors and vehicle types are diverse and such delineation was considered important for scoring. A similar delineation of discrete technology options was not done for LDV use cases.[26] See Annex 4 for further details.[27]

Steps to Assess Use Case Value

The process adopted by the Working Group to assess use case value within this framework consisted of four steps.[28] The Working Group methodically went through each of these steps. The results are described below. See Annex 4 for more details of this process.

Step (a) Identify use cases potentially providing value
Step (b) Screen use cases based on whether seven criteria for providing value are met
Step (c) Score use cases in terms of potential benefits, costs, and ease/risk of implementation
Step (d) Rank use cases based on the scoring results of Step (c)

Step (a) Use case development (submissions from participants). Participants were invited to submit any number of use cases they believed should be considered, by providing the five dimensions of a specific recommended use case from those shown in Table 2. There were a total of 2,652 possible use cases to choose from in making submissions, defined by all possible permutations. In total, nineteen Working Group participants submitted a total of 1,060 unique use cases. The submitted use cases considered sectors, applications, types, approaches, and vehicle types and technology characteristics that could potentially provide value in the short-term ("now") timeframe to 2022, consistent with PUC Question (a).[29] However, the Working Group recognized that many of the submitted use cases, and many that were not submitted, could provide value in the medium- and long-term beyond 2022. It was particularly difficult to identify MHDV use cases for the medium- and long-term, given the many newly emerging types of electric MHDVs. Submitted use cases are available to view and download in the Use Case Assessment Database.[30]

Step (b) Screening. All 1,060 submitted use cases were then screened as either "pass" or "fail" for the short-term ("now") timeframe to 2022. This was done according to the methodology's seven screens for technological feasibility (Screen 1), wholesale and retail market participation rules (Screens 2a-2b),

---

[26] Different charger power levels were defined as technology variants for a handful of the LDV use cases; and ranges of battery capacity were noted for many of the use cases. However, the variations were much narrower and less diverse for LDVs than for MHDVs, in part due to the more standardized mass-market nature of LDVs.
[27] For more background on MHDV use cases, see also the white paper developed as part of the Working Group, "Development of Market Analysis and Use-Cases for Medium & Heavy-Duty Vehicle- Grid Integration," linked in Annex 1.
[28] The original methodology developed by the Working Group consisted of six steps, the first being the selection of the framework and the sixth being creating policy recommendations. The first step on selection of the framework is documented in the material provided in Annex 1 and further explained in Annex 2. This "first step" is not elaborated here because the focus of this report is on answering the PUC Questions and not on developing a methodology. The sixth step of the methodology is covered by the work described in Section B. The four steps (a)-(d) outlined here correspond to Steps 2-5 of the formal methodology referenced in Annexes 1 and 2.
[29] PUC Question (a) asks for use cases that can provide value "now." The Working Group engaged in considerable discussion of the meaning of "now" during the use case submission, screening, and scoring steps, and confirmed an understanding that "now" was the short-term period 2020-2022 for purposes of use case assessment. Beyond "now," the Working Group defined "medium-term" as 2023-2025 and "long-term" as 2026-2030 for the purposes of policy recommendations in Section B.
[30] The Use Case Assessment Database is available online at https://airtable.com/shrHTfpCQ7lFjFY9l. Database tables can be viewed and downloaded from that link, and Excel versions are also available directly via the links in Annex 1.

consumer adoption/acceptance (Screens 3a-3b), and availability of data needed to assess the use case (Screens 4a-4b). If a use case passed all seven screens, it was then scored by the Working Group in Step (c). The screening criteria were developed specifically in relation to PUC Question (a) as providing value in California by 2022. The screening resulted in 355 use cases "passing" as potentially providing value by 2022.[31] There were also over 1000 individual comments on screening of individual use cases, for example to explain reasons for failing particular screens or to provide supplementary information. Screening results and comments are available to view and download in the Use Case Assessment Database.[32]

Step (c) Scoring. The use cases that passed screening were then "scored" on their relative benefits, costs, and ease/risk of implementation:

- Benefits were scored according to two parameters: (1) The estimated benefit in dollars per EV per year from VGI for the use case, and (2) the estimated aggregate number of vehicles ("population") that could participate in that VGI use case by 2022.[33] Participants conducting the scoring were asked to rate a given use case using five pre-defined ranges for each parameter, see Annex 4 for the specific ranges. The assessed total benefit score for each use case ($/year as a state-wide aggregate) was the product of these two parameters.[34] Note that the population dimension for benefits reflects technical potential of the total vehicles with technical capability to participate in VGI programs or incentives, not the actual number of vehicles that would be participating, which also requires considering factors like customer education, marketing effectiveness, and adoption rates, factors the Working Group was not able to consider.

- Costs were scored on a relative scale of 1-5 for "very high" to "very low" costs. During the scoring step, there was considerable discussion of the availability of cost data and the need to score costs on a relative rather than an absolute basis in the absence of cost data.[35] The Working Group decided to employ relative cost scoring because absolute costs for various use cases were difficult to obtain given time and confidentiality constraints – some of the private-sector participants said they were unable to share cost information for a number of reasons, including anti-trust and competitiveness concerns. This also meant that the Working Group could not make true cost-benefit comparisons for the use cases because costs were only scored on a relative basis. A number of policy recommendations in Section B support further work on cost data and cost-benefit comparisons.

---

[31] Note that some of the use cases that passed screening were designated as "disputed passes" by the Working Group. This meant one participant or scoring team deemed the use case to pass, and at least one other participant or scoring team deemed it to fail. See the "Stage 1 Report" linked in Annex 1 for details.
[32] See Footnote 30.
[33] The scoring of benefits of each use case was based on either customer benefits for customer applications, or system benefits for system applications. System benefits include benefits to ratepayers, and could account, for example, for avoided power system upgrade costs, as well as potential downward pressure on electricity rates to the benefit of all customers as through the acceleration of EV adoption and resulting increase in electricity sales. The factors taken into account by participants in scoring use cases were partially but not fully documented in their comments on scoring, which are available online (see Annex 1 for links to Working Group materials).
[34] Total benefit score was the logarithm of the average $/vehicle/year score for a given use case times the average population for the use case. Total benefit scores of the 320 scored use cases ranged from 4.8 to 8.3.
[35] See in particular the document "IOU Perspective on VGI Use-case Benefits and Costs" linked in Annex 1.

- Ease/risk of implementation was similarly scored on a relative scale of 1-5, from "very difficult and risky" to "very easy and not risky." A low score for ease/risk of implementation was also intended to point to significant barriers that should garner policy-maker attention.

- In total, 320 use cases out of the 355 use cases that passed screening were scored with at least a partial benefit score.[36] There were also 660 individual text comments submitted with the numerical scoring. For example, some comments on the scoring pointed to why specific use cases received a high or low score for ease/risk of implementation. Scoring results and comments are available to view and download in the Use Case Assessment Database.[37]

Step (d) Ranking. The Working Group did not agree upon one specific ranking of the 320 use cases as to which would provide higher or lower value. However, participants also recognized that policy-making would be difficult if all 320 use cases were left undifferentiated, so the Working Group defined several "subsets" of use cases that might be considered "higher value" or "high scoring" or "priorities" or "favorable." All of these subsets were assessed by the Working Group as having merit and useful for further work.

Results of Use Case Scoring

Figure 1 shows the distribution of benefit scores across all 240 LDV use cases. The figure shows both benefit metrics side-by-side for each use case – the scored "$/EV/year" metric (with use cases sorted from low to high) and the associated scored "EV Population" metric for each use case, for the population of EVs that could participate in that use case by 2022.[38]

The total benefit of a given use case is the product of these two benefit metrics. Figure 1 shows that many use cases with low $/EV/year scores have high population scores, so that the total benefit for these use cases can still be high. Conversely, many use cases with high $/EV/year benefit scores have low population scores, so the total benefit may be low.

It should also be noted that some use cases shown in Figure 1 may have higher benefits than shown by the maximum axis value of $800/EV/year; see "Scoring the Benefit Metric $/EV/year" on the next page.

[36] "Partial benefit score" means either a $/EV/year score or an EV Population score. The total of 320 scored use cases does not include a number of technology and vehicle-type variants of the same use case, see Annex 4 for details on the MHDV technology variants. There were 5 LDV technology variants and 83 MHDV technology variants also scored; these technology variants are included in the listing in Annex 5 and listed separately in the Use Case Assessment Database. In total in the database there are 437 use cases and technology variants of those use cases that passed screening.
[37] See Footnote 30.
[38] The data used in Figure 1 comes solely from the estimates made by Working Group participants in their scoring of the use cases (see Annex 4). Figure 1 does not reflect directly upon any external studies or analysis, although participants may have used external sources in making estimates, and if so, they were asked to document this in scoring comments.

Scoring the Benefit Metric $/EV/year

The benefit metric $/EV/year was scored according to five multiple-choice options for LDV use cases: $1-50, $50-150, $150-300, $300-600, and $600-1000 (see Annex 4). Ranges for MHDV scoring were a factor of ten higher, so the highest MHDV range was $6,000-10,000. When calculating the average score for a given use case based on scores submitted by participants, the mid-point of these ranges was used. Thus, the highest average score possible is $800/EV/year for an LDV use case, given the multiple-choice options available to scorers. Six LDV V2G use cases received this highest average score of $800/EV/year, as reflected in Figure 1. If scorers wanted to score a use case higher than the highest option, they were instructed to so indicate in their scoring comments. Comments for at least three LDV V2G use cases indicated that the benefit should be scored as high as $3000/EV/year for those use cases. For MHDV scoring, eight V1G and five V2G use cases were scored with the highest option of $8,000/EV/year, and comments indicated that scores should be higher than $10,000/EV/year for some of those.

There are some use cases with both high $/EV/year scores and high population scores, and these result in high total scored benefits:

- The highest total scored benefit from a single LDV use case is $200 million/year from Use Case #1, residential single-family home V1G with indirect control of charging, for customer bill management.
- The second highest total scored benefit is $160 million/year from Use Case #4, residential single-family home V1G with direct control of charging, for customer bill management.
- The third highest total benefit, also $160 million, is from Use Case #827, for commercial workplace V2G with direct control of charging, for customer bill management. However, V2G use case #827 has a low average score for ease/risk of implementation.
- There are a further 15 use cases that also have a low average score for ease/risk of implementation but that have a high total benefit ranging from $10 million to $100 million. To the extent that policy could remove barriers that would improve the ease/risk of implementation, these use cases might be targeted by policy as unlocking high value.[39]
- There are a further two use cases with total benefit above $100 million and high scores for ease/risk of implementation, for rideshare vehicle charging in single-family homes and public destination.[40]

Figure 2 shows the distribution of total benefit in dollars per year across all use cases, which is the product of the $/EV/year metric and the population metric. As can be seen, total benefits from LDV use cases are in general significantly higher than benefits from MHDV use cases according to the scoring by Working Group participants, due in part to higher assessed EV populations for LDV in the short-term. The highest total benefit among MHDV use cases was $16 million/year, for small truck fleet charging with either direct or indirect control, for customer bill management (Use Cases #2245 and #2248).

[39] These 15 use cases are the V1G use cases 498, 906, 918, 1026, 1110, 1121, 1230, 1334, 1434, 1442; and the V2G use cases 115, 118, 1028, 1436, 1544.
[40] These two use cases are 205 and 1226.

Figure 1: Distribution of Average Benefit Scores for LDV Use Cases
($/EV/year and EV Population)

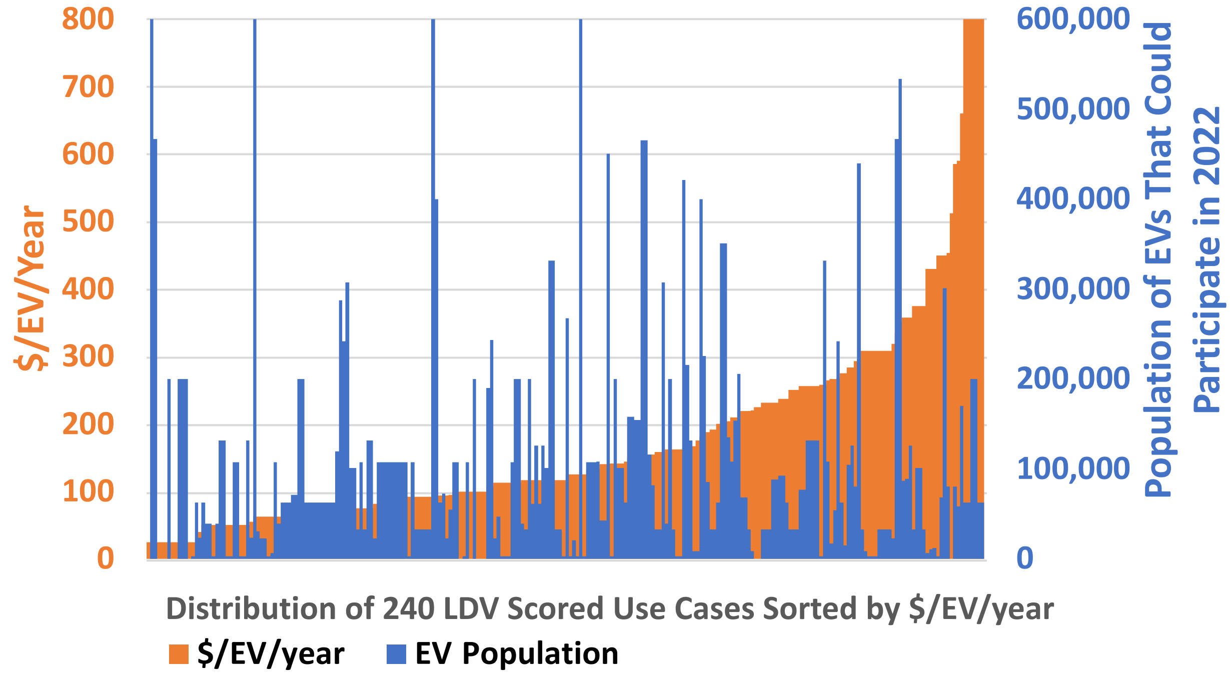


Figure 2: Distribution of Total State-Wide Benefit in 2022
as Scored Across All Use Cases ($/year)

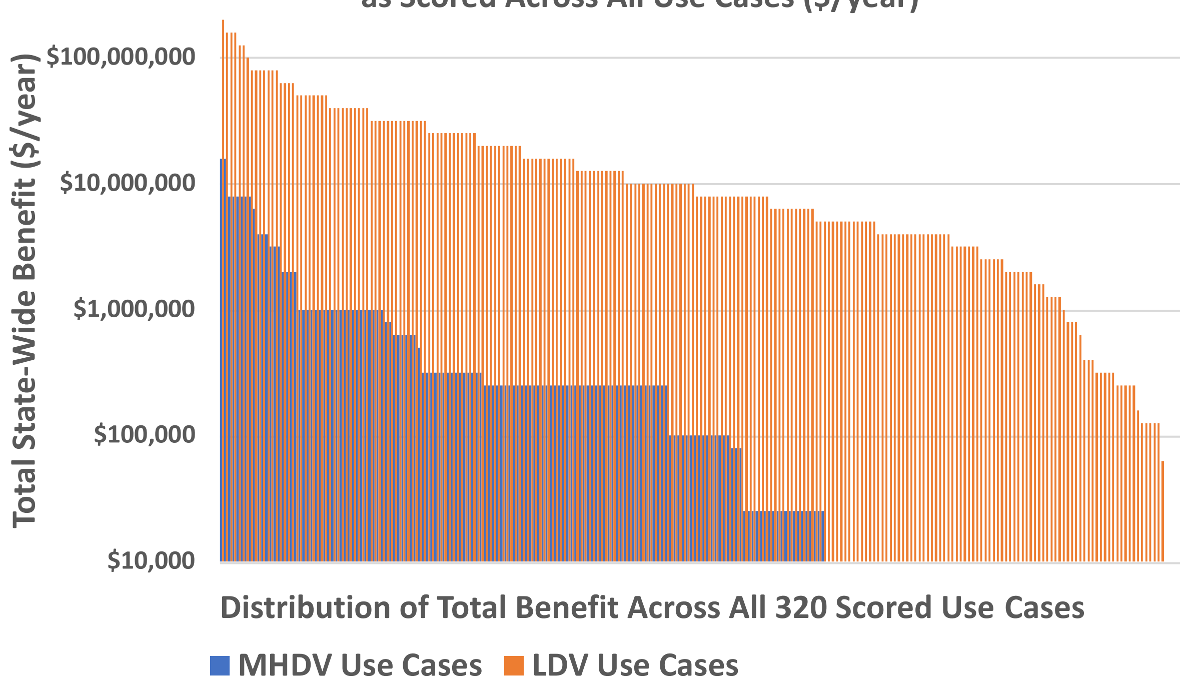


Figure 3: Distribution of Average Cost Scores

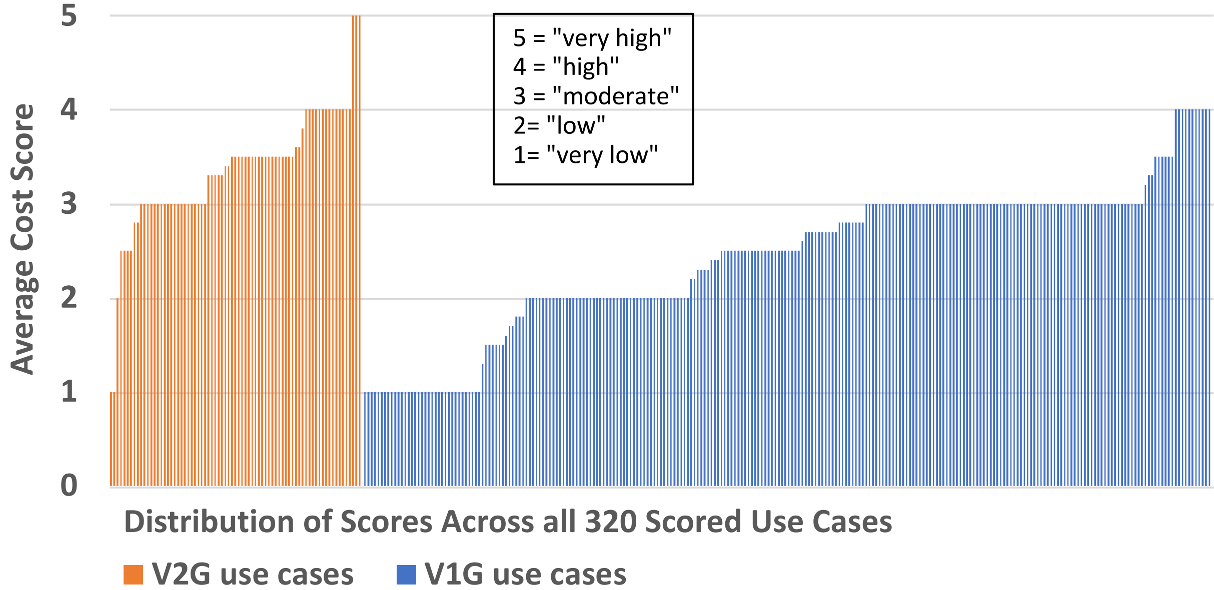
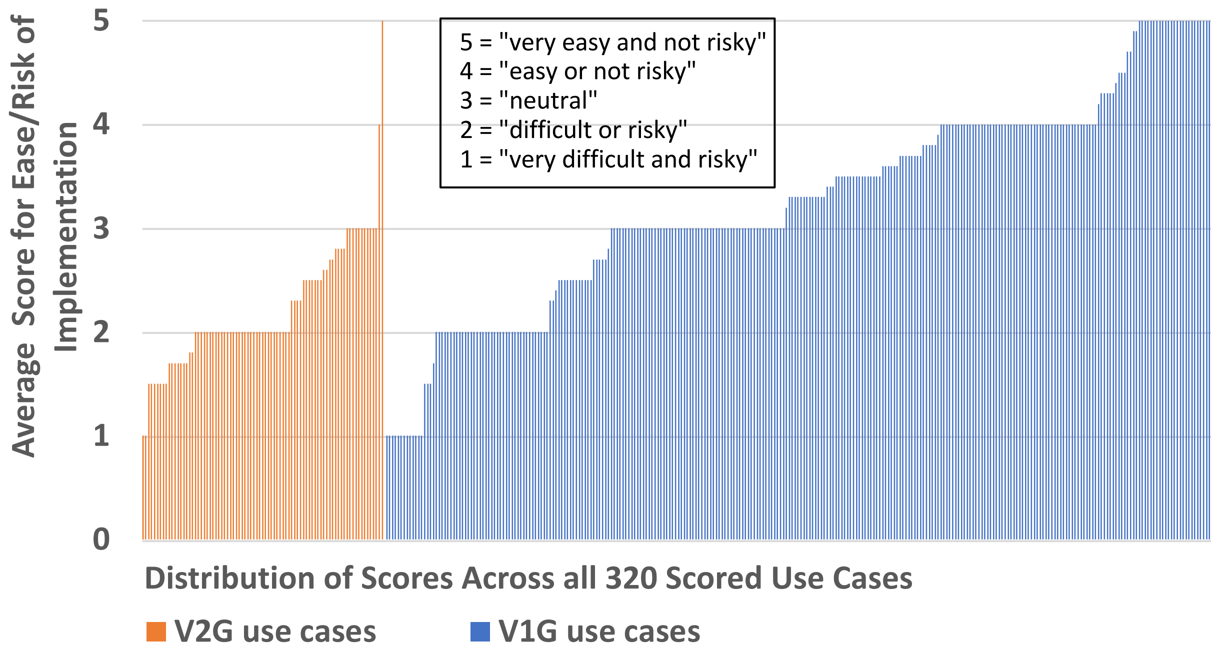


Figure 4: Distribution of Average Scores for Ease/Risk of Implementation



Working Group Answers to PUC Question (a)

The conclusion of the Working Group was that all use cases that passed screening and received at least a benefit score should, for the purposes of this report, be considered as "able to provide value now."[41] These 320 use cases are given in Annex 5. Most Working Group participants agreed that no scored use case should be excluded from being considered as "able to provide value now," since all use cases that passed screening and received a benefit score indicated at least some value.[42]

However, the value perceived by Working Group participants for these use cases varied widely on a broad spectrum, when benefits, costs, and the ease and riskiness of implementation (related to barriers and many other factors) are taken into account. For example, high-cost and low-benefit use cases should not be viewed the same as low-cost and high-benefit use cases. Therefore, it is clear that these 320 use cases should not all be treated equally in policy-making, but should be differentiated across a spectrum of value. Furthermore, many other use cases developed by the Working Group beyond these 320 use cases have the potential to provide value in the medium- and long-term.

Since the scoring of use case costs and the ease and risk of implementation was relative, meaning that costs could not be compared with benefits, the Working Group was unable to arrive at any quantitative assessment of "net value." Nevertheless, as noted above, during the ranking step of the use case assessment process, the Working Group solicited from participants and documented a number of suggested "subsets" of use cases that might be termed "higher value" or "high scoring" or "favorable," although no such terms were agreed upon by the Working Group. All of these subsets were assessed by at least some participants as having merit and useful for further work.

Highlighting or Ranking Use Case Value

Based on use case scoring, a number of "subsets" of smaller groups of use cases were developed by the Working Group for highlighting or ranking use case value, summarized below. These are provided as part of the Working Group's answer to PUC Question (a).

1. "Consensus use cases." Most Working Group participants agreed that priority sectors and applications for use cases providing value in the short-term include the following:[43]

- Residential sector broadly, for LDV use cases
- Commercial workplace sector broadly, for LDV use cases

[41] Use cases receiving at least a benefit score means that at least one participant scored the use case for benefits, either for the $/EV/year benefit metric, and/or for the metric total population of EVs that could participate by 2022. There was some debate about whether use cases scored on only one of these metrics be excluded, since the full benefit result of multiplying the two metrics together could not be obtained, most participants agreed to include the use case if only one of these metrics was scored.

[42] The conclusion that all use cases with benefits should, for the purposes of this report, be considered as "able provide value now" should only be interpreted as an answer to PUC Question (a), and does not imply that programs to enable these use cases necessarily maximize benefits and minimize costs.

[43] The Working Group agreed to call these "consensus use cases" even though a few participants were not in full agreement with this term or with every aspect of the subset definition. PUC Question (a) uses the word "now" and as noted previously, the Working Group interpreted "now" to mean the short-term through 2022.

- Customer bill management
- Distribution upgrade deferrals
- Home and building backup power (V2H and V2B)
- Commercial sector demand-charge management (customer bill management)
- V2G that can provide value now, including V2G use cases in the bullets above
- System applications easily implementable for vehicle locations with daytime charging ability
- Vehicle types with excess battery capacity relative to duty cycle, such as school buses
- All system and customer applications that defer charging away from peak periods

2. Honda value-metric subset. Honda defined a "value metric" that integrated all three metrics of benefits, costs, and ease/risk of implementation, as a simple way to rank the scored use cases considering all three metrics. This metric gives a means to focus on a set of high-value use cases for more in-depth analysis. The metric Honda developed was the simple multiplication of the benefit score times the cost score (inverted so lowest cost gives the highest score) times the score for ease/risk of implementation. This three-item product gives a single value that can be ranked. Honda also pointed to the text comments that participants made while scoring the use cases, and suggested that comments for the high-value use cases identified through this metric be examined in depth, as to commonalities, context, trends, and drivers for specific use cases based on existing policies and programs.

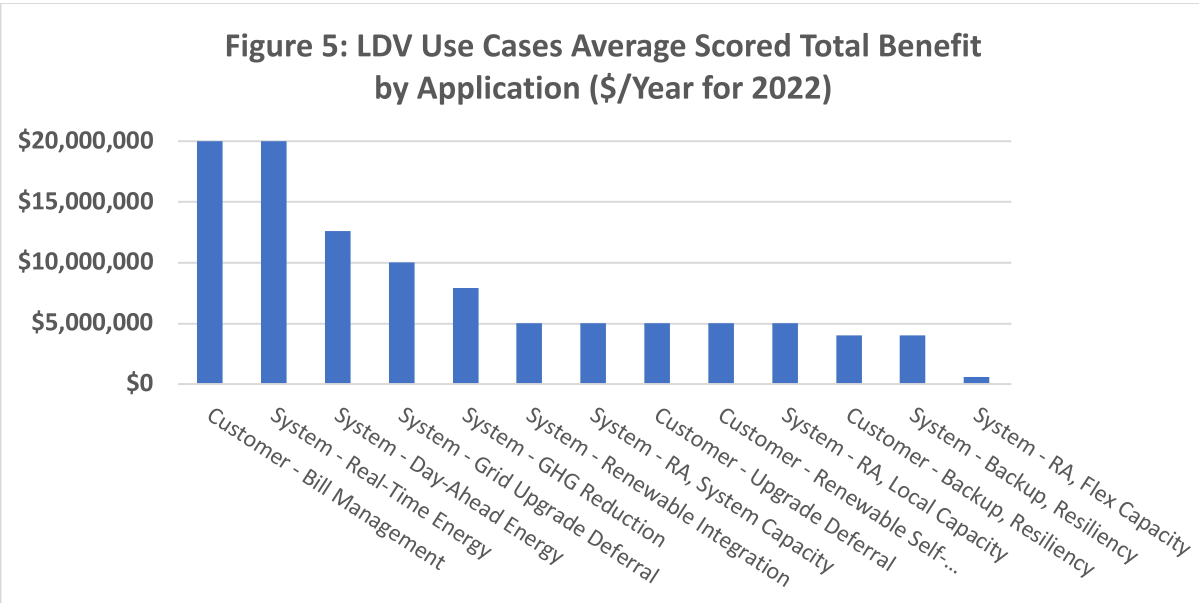
3. Ford high-value subset. Ford suggested filtering for high-value LDV use cases that provide at least $150 in value per EV per year, and that received a score for ease/risk of implementation of either "very easy and not risky" (score of 5 on scale of 1-5) or "easy or not risky" (score of 4). Ford suggested that after such filtering, each of the high-value use cases should be reviewed to brainstorm the policy and industry actions required to catalyze implementation and capture that value.

4. Gridworks above-median subset. This subset defines a use case as providing higher value if all three metrics for a given use case -- benefits, costs, and ease/risk of implementation -- were each scored above the median value of all use cases scored for that metric. Separate medians were employed for LDV vs. MHDV use cases. "Above median" is a standard method of distinguishing "high" from "low" in any groupings, and Gridworks as the Working Group facilitator applied this standard method to compare against the other subsets.

5. Karim Farhat Prime Flex subset. This subset defines a fully scored use case as "favorable" if at least one party deemed it as such. By design, the methodology did not rely on scoring averages, in order to be as inclusive as possible. The threshold for defining a use case as "favorable" is: a minimum total state-wide benefit of at least $100,000 per year from the estimated EV population that could participate by 2022; a cost score of "low" or "very low"; and an ease/risk of implementation score of either "very easy and not risky" or "easy or not risky" (for further details see material linked in Annex 1).

6. Nissan analysis by application and sector. Nissan analyzed average benefit scores by application, to organize the screening results of the 17 defined use case applications with the highest benefit scores. See the Nissan document linked in Annex 1 for details. The highest LDV scores were for customer bill management, system real-time energy, system day-ahead energy, and system grid upgrade deferral applications. The highest MHDV scores were for customer bill management, customer renewable self-consumption, system RA (system capacity), system day-ahead energy, and customer backup/resiliency applications. Nissan also analyzed average benefit scores by sector. The highest scoring sectors were residential single-family home, residential single-family-home rideshare, commercial public commute, and commercial workplace.

Figure 5 shows the Nissan analysis applied to LDV use cases by application. The "average scored benefit" is the product of the $/vehicle/year benefit metric and the "population" benefit metric for each use case, and then averaged across all use cases for that application. The "population" benefit metric for each use case is the scored level of EV population for that use case that could technically participate in VGI programs by 2022, not considering program participation levels (see description of scoring above).



Any one of the subsets defined above could be chosen and analyzed, in terms of value of the use cases and detailed understanding of benefits, costs, and ease/risk of implementation. The text comments provided with scoring submissions provide a further pool of insight on the use cases within these subsets. Designations of which use cases fall into which subsets are contained in the Use Case Assessment Database.[44]

Insights from Use Case Subsets

There are 29 LDV use cases that simultaneously appear in all of the defined subsets above. This means these use cases are scored highly in a robust manner—they score highly across a number of different metrics simultaneously. All of these use cases are V1G, as no V2G use cases were highly scored enough to appear in all subsets. This is generally because, while many V2G use cases were scored highly for total benefits, they were often scored as having higher costs and less ease or higher risk of implementation. Figures 6 and 7 show the sectors and applications associated with these 29 use cases.[45]

[44] See Footnote 30. All use case material is also available as a series of Excel files linked in Annex 1.
[45] Rideshare vehicle charging in Figure 6 is distributed across a number of different residential and commercial sectors.

Figure 6: Sectors of LDV Use Cases Appearing in All Subsets

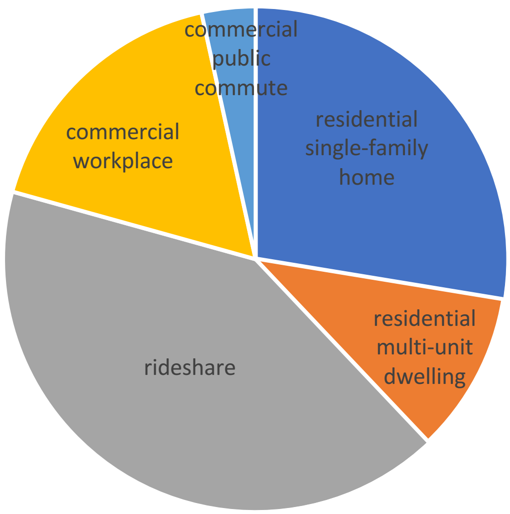
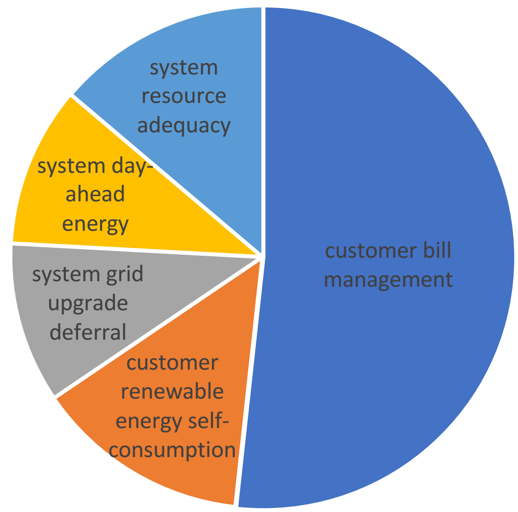


Figure 7: Applications of LDV Use Cases Appearing in All Subsets



Insight from a Particular Subset and Definition of Value

To illustrate the insight that can be gained from looking through the lens of a particular subset using a particular definition of value, Tables 3 and 4 show the top-25 ranked LDV and MHDV use cases according to the Honda value metric. Again, all are V1G use cases for reasons noted above. It can be seen that:

- The majority of LDV use cases are for residential single-family homes, with five use cases for commercial workplace, four use cases for residential multi-unit dwellings, and three use cases for commercial public commute (i.e., public parking).
- The majority of MHDV use cases are for small trucks, with an additional four use cases for large trucks, six use cases for transit buses, and two use cases for school buses.
- LDV customer applications are for bill management and grid upgrade deferral across all sectors, and for renewable self-consumption in both residential and commercial workplace use cases.
- Customer bill management is the main application for large and small trucks and school buses.
- Small truck use cases provide the greatest number of different applications -- customer bill management, customer renewable energy self-consumption, system renewable energy integration, system day-ahead energy, and system GHG reduction.
- There are six rideshare vehicle charging use cases, for charging both in residential single-family homes and multi-unit dwellings, and for the commercial public commute sector (i.e., charging in public parking).
- Commercial workplace bill management and renewable self-consumption are both unified and fragmented, meaning scoring deemed both options to be high-value – charging infrastructure operated by the workplace entity, and charging operated by a third party or aggregator.

Table 3. Top-25 Ranked LDV Use Cases According to Honda Value-Metric

ID	Sector**	Application	Approach	Resource*
1	Residential - Single Family Home	Customer - Bill Management	Indirect	Unified
13	Residential - Single Family Home	Customer - Upgrade Deferral	Indirect	Unified
16	Residential - Single Family Home	Customer - Upgrade Deferral	Direct	Unified
37	Residential - Single Family Home	Customer-Renewable Self-Consumption	Indirect	Unified
49	Residential - Single Family Home	System - Grid Upgrade Deferral	Indirect	Unified
109	Residential - Single Family Home	System - Renewable Integration	Indirect	Unified
121	Residential - Single Family Home	System - GHG Reduction	Indirect	Unified
133	Residential - Single Family Home	System - RA, System Capacity	Indirect	Unified
148	Residential - Single Family Home	System - RA, Flex Capacity	Direct	Unified
160	Residential - Single Family Home	System - RA, Local Capacity	Direct	Unified
205	Residential - Single Family Home, Rideshare	Customer - Bill Management	Indirect	Unified
241	Residential - Single Family Home, Rideshare	Customer-Renewable Self-Consumption	Indirect	Unified
313	Residential - Single Family Home, Rideshare	System - Renewable Integration	Indirect	Unified
337	Residential - Single Family Home, Rideshare	System - RA, System Capacity	Indirect	Unified
410	Residential - Multi-Unit Dwelling	Customer - Bill Management	Indirect	Fragmented
458	Residential - Multi-Unit Dwelling	System - Grid Upgrade Deferral	Indirect	Fragmented
518	Residential - Multi-Unit Dwelling	System - Renewable Integration	Indirect	Fragmented
614	Residential - Multi-Unit Dwelling, Rideshare	Customer - Bill Management	Indirect	Fragmented
817	Commercial - Workplace	Customer - Bill Management	Indirect	Unified
818	Commercial - Workplace	Customer - Bill Management	Indirect	Fragmented
830	Commercial - Workplace	Customer - Upgrade Deferral	Indirect	Fragmented
853	Commercial - Workplace	Customer-Renewable Self-Consumption	Indirect	Unified
854	Commercial - Workplace	Customer-Renewable Self-Consumption	Indirect	Fragmented
866	Commercial - Workplace	System - Grid Upgrade Deferral	Indirect	Fragmented
1753	Commercial - Public Commute, Rideshare	System - GHG Reduction	Indirect	Unified
1430	Commercial - Public Commute	Customer - Bill Management	Indirect	Fragmented
1514	Commercial - Public Commute	System - Day-Ahead Energy	Indirect	Fragmented

(*) Resource is "aligned" for all entries

Table 4. Top-25 Ranked MHDV Use Cases According to Honda Value-Metric

ID	Sector	Application	Type	Resource*	Vehicle Type**
1837.2	Commercial-Fleet, Transit Bus	Customer - Bill Management	Indirect	Unified	LR Transit Bus A
1837.3	Commercial-Fleet, Transit Bus	Customer - Bill Management	Indirect	Unified	LR Transit Bus B
1838.2	Commercial-Fleet, Transit Bus	Customer - Bill Management	Indirect	Fragmented	LR Transit Bus A
1921.2	Commercial-Fleet, Transit Bus	System - Day-Ahead Energy	Indirect	Unified	LR Transit Bus A
1921.3	Commercial-Fleet, Transit Bus	System - Day-Ahead Energy	Indirect	Unified	SR Transit Bus B
1969.2	Commercial-Fleet, Transit Bus	System - RA, System Capacity	Indirect	Unified	LR Transit Bus A
2041	Commercial-Fleet, School Bus	Customer - Bill Management	Indirect	Unified	
2042	Commercial-Fleet, School Bus	Customer - Bill Management	Indirect	Fragmented	
2245	Commercial-Fleet, Small Truck	Customer - Bill Management	Indirect	Unified	
2245.1	Commercial-Fleet, Small Truck	Customer - Bill Management	Indirect	Unified	Small Truck B
2246	Commercial-Fleet, Small Truck	Customer - Bill Management	Indirect	Fragmented	
2246.1	Commercial-Fleet, Small Truck	Customer - Bill Management	Indirect	Fragmented	Small Truck B
2248.1	Commercial-Fleet, Small Truck	Customer - Bill Management	Direct	Unified	Small Truck B
2281	Commercial-Fleet, Small Truck	Customer-RE Self-Consumption	Indirect	Unified	Small Truck B
2284	Commercial-Fleet, Small Truck	Customer-RE Self-Consumption	Direct	Unified	Small Truck B
2329.1	Commercial-Fleet, Small Truck	System - Day-Ahead Energy	Indirect	Unified	Small Truck B
2353	Commercial-Fleet, Small Truck	System - Renewable Integration	Indirect	Unified	Small Truck B
2354	Commercial-Fleet, Small Truck	System - Renewable Integration	Indirect	Fragmented	Small Truck B
2356	Commercial-Fleet, Small Truck	System - Renewable Integration	Direct	Unified	Small Truck B
2365	Commercial-Fleet, Small Truck	System - GHG Reduction	Indirect	Unified	Small Truck B
2368	Commercial-Fleet, Small Truck	System - GHG Reduction	Direct	Unified	Small Truck B
2449.1	Commercial-Fleet, Large Truck	Customer - Bill Management	Indirect	Unified	Large Truck A
2450.1	Commercial-Fleet, Large Truck	Customer - Bill Management	Indirect	Fragmented	Large Truck A
2452.1	Commercial-Fleet, Large Truck	Customer - Bill Management	Direct	Unified	Large Truck A
2458.1	Commercial-Fleet, Large Truck	Customer - Bill Management	Direct	Unified	Large Truck A

(*) Resource is "aligned" for all entries. (**) For details on vehicle types, see Annex 3. LR = long range, SR = short range.

V2G Use Cases

There are 80 V2G use cases among the 320 scored use cases. Figures 8 and 9 show the distribution of sectors and applications for these V2G use cases. As stated previously, many of these V2G use cases are scored highly for benefits, but most are scored as having higher costs and/or less ease or higher risk of implementation, thus they do not appear in the defined subsets. Among these 80 V2G use cases are 7 that appear in at least one of the subsets, for residential single-family homes and commercial workplaces and for backup/resiliency, bill management, and renewable self-consumption (Table 5).

Figure 8: Sectors of All V2G Use Cases

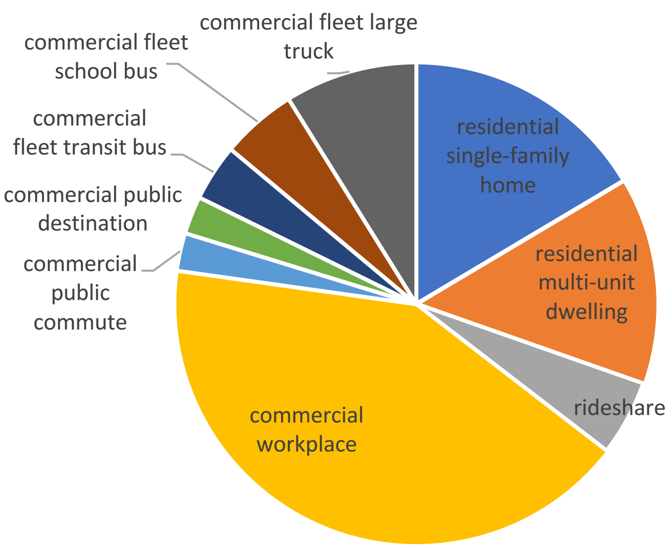


Figure 9: Applications of All V2G Use Cases

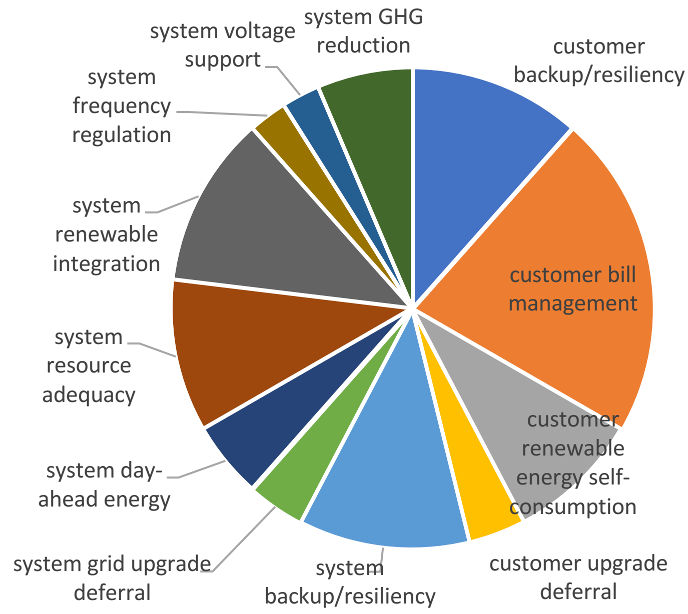


Table 5. V2G Use Cases Appearing in High-Scoring Subsets

ID	Sector	Application	Type	Resource*
31	Residential - Single Family Home	Customer - Backup, Resiliency	Indirect	Unified
34	Residential - Single Family Home	Customer - Backup, Resiliency	Direct	Unified
826	Commercial - Workplace	Customer - Bill Management	Direct	Unified
850	Commercial - Workplace	Customer - Backup, Resiliency	Direct	Unified
860	Commercial - Workplace	Customer-Renewable Self-Consumption	Indirect	Fragmented
872	Commercial - Workplace	System - Grid Upgrade Deferral	Indirect	Fragmented
2458	Commercial - Fleet, Large Truck (class 6-8)	Customer - Bill Management	Direct	Unified

(*) Resource is “aligned” for all entries

Towards Further Development of Use Case Understanding

The summaries and insights provided in this section are but a slice of the total insights possible–the Working Group generated a wealth of information on over 1,000 VGI use cases. The use cases that were screened out from this initial set of 1,000 could still provide value in the future, and text comments on screening and further documented screening insights generated by the screening teams can help further distinguish high-value use cases beyond the short-term (see Annex 1 for links to all this material). Of the 320 use cases that received scores for benefits, costs, and/or ease/risk of implementation, many can be ranked or prioritized in different ways to give particular perspectives on value, also considering the 660 individual comments generated by participants while scoring use cases.

As noted above, there are many use cases with low $/EV/year benefit scores but high population scores, so that the total benefit for these use cases can still be high. And conversely, many use cases with high $/EV/year benefit scores have low population scores, so the total benefit may be low. There are also use cases with both high $/EV/year scores and high population scores, and these result in highly scored total statewide benefits. The highest total benefit from a single LDV use case is $200 million/year, and from an MHDV use case is $16 million/year.

The good news is that there are many potential VGI use cases which can provide value. And the potential market for VGI is diverse, complex and interwoven across a broad swath of the power and transportation sectors. Given the use case assessment work performed by the Working Group, it appears that the work of developing VGI markets will demand persistent experimentation for the next several years, rather than simple broad, sweeping strokes that can happen quickly. Importantly, leaders from both the demand and supply sides of the nascent VGI market agree California should take an inclusive approach to potential VGI opportunities.

SECTION B. PUC QUESTION (B) WHAT POLICIES NEED TO BE CHANGED OR ADOPTED TO ALLOW ADDITIONAL USE CASES TO BE DEPLOYED IN THE FUTURE?

The Working Group developed a set of 92 individual recommendations for policy actions that California state agencies, utilities, CCAs, other LSEs, and the California ISO could undertake to advance VGI in the short-, medium-, and long-term.[46] The full text of all 92 recommendations is given in Annex 6. These recommendations are separated into 11 different policy categories (Table 6).

Table 6. Policy Categories

#	Category
1	Reform retail rates
2	Develop and fund government and LSE customer programs, incentives, and DER procurements
3	Design wholesale market rules and access
4	Understand and transform VGI markets by funding and launching data programs, studies and task forces
5	Accelerate use of EVs for bi-directional non-grid-export power and PSPS resiliency and backup
6	Develop EV bi-directional grid-export power including interconnection rules
7	Fund and launch demonstrations and other activities to accelerate and validate commercialization
8	Develop, approve, and support adoption of technical standards not related to interconnection
9	Fund and launch market education & coordination
10	Enhance coordination and consistency between agencies and state goals
11	Conduct other non-VGI-specific programs and activities to increase EV adoption

Together, these categories address virtually all aspects of policy support for the VGI use cases providing value in the short-term, as well as many use cases which could potentially provide value in the medium- and long-term:

- Category 1, reforming retail rates, can support both “indirect” use cases, for which charging decisions can be based on time-varying price signals (such as TOU rates), and “direct” use cases where new rates can improve cost-effectiveness or provide new incentives for managed charging.
- Category 2, public and ratepayer funds for government and LSE customer programs, incentives, and procurements can support scale-up and cost reduction of already-commercial VGI solutions for most V1G use cases, as well as already-commercial V2G use cases.
- Category 3, recommendations addressing wholesale market rules and access can support use cases for system applications, including a wide variety of grid services, from day-ahead and real-time energy to resource adequacy, renewable energy integration, and grid upgrade deferrals.
- Category 4, further information on customer engagement, costs, benefits, and scale, can support market-based knowledge and information for reducing costs and removing barriers of use cases that may be under-employed currently but promise high value if market barriers are removed.

[46] All details and information about the policy recommendations are contained in the Policy Recommendations Database, available online at https://airtable.com/shr9JBvC2bAofuJpj. Database tables can be viewed and downloaded from that link and Excel versions are also available directly via the links in Annex 1.

- Category 5, on power generation not exported to the grid, can support behind-the-meter V2B and V2H use cases for customer backup and resiliency, including resiliency to counteract Public Safety Power Shutoffs (PSPS).
- Category 6, on power generation exported to the grid, can support grid-facing V2G use cases, such as system renewable energy integration, system resource adequacy, and system ancillary services like frequency regulation.
- Category 7, on public funding of demonstrations and commercialization activities, can support enhanced knowledge and market development for VGI solutions that are in the process of being fully commercialized.
- Categories 8-11 can support a wide variety of other programs and activities that can contribute to market development, technical standards, and coordination to address VGI in an integrated manner across state agencies.

<u>Policy Recommendations Classification (Degree of Agreement) Based on Survey Results</u>

To gain further insight into the policy recommendations and to classify the recommendations by degree of agreement from participants, the Working Group conducted a survey of participants and asked them four questions about each of the 92 recommendations (see Annex 2 for survey details):[47]

Policy Survey Questions

1. Do you agree or disagree that this recommendation will advance VGI in California?
2. How clear, understandable, and policy ready is this recommendation?
3. How critical and relevant is this policy to meeting your organization's own VGI objectives?
4. Any other comments on this recommendation?

The possible responses to Question #1 on whether respondents agree with a given recommendation were "strongly agree", "agree", "neutral", "disagree", and "strongly disagree." The Working Group utilized these responses to classify the policy recommendations into "strongest agreement," "good agreement," "majority neutral," and "majority disagree."[48] Table 7 gives the criteria for all classifications and the number of recommendations so classified. Medium- and long-term recommendations were put into a separate classification to allow a sharper focus on the short-term, given the large number of short-term recommendations.

Tables 8-13 in the following sub-sections list the policy recommendations within each of these classifications. The divergence or convergence of survey responses, that is, the degree to which

[47] This survey was conducted on an expedited basis and not all policy recommendations were clear at the time. Survey responses remain anonymous and do not constitute formal institutional comment on policy proposals.
[48] The Working Group did not use the results of Questions #2 or #3 in assessing recommendations, but full survey results are available for further analysis; see Annex 1 for links to this material. Annex 8 lists the roughly 1200 comments received in response to Question #4 and Annex 9 shows graphically the scores for Questions #1 to #3.

respondents agreed with each other in rating a policy, is also noted in the following sub-sections, as either “strong convergence,” “broad convergence,” or “divergence of responses.”[49]

Table 7. Classification of Policy Recommendations

Count	Classification	Criteria for Classification
23	Strongest agreement	Agree or strongly agree > 66% and strongly disagree < 20%
15	Good agreement	Agreement > disagreement and agreement > neutral
16	Majority neutral	Neutral > 50% [50]
7	Majority disagree	Disagreement > 50%
16	Policy action already underway	CPUC Energy Division staff comments so indicates
15	Medium-term and long-term	Policy recommendation timeframe so indicates
92	Total	

It must be noted that the classification for about one-fifth of the policy recommendations in this section may be less valid than for the others because the recommendations were re-worded by the original submitters after the survey was taken. Survey results on these re-worded recommendations may not as accurately reflect agreement with the current wording compared to recommendations whose wording remained unchanged. There was no time to re-conduct the survey and the Working Group, as it was concluding, believed it was in the best interest of clear policy-making to allow the re-wording. [51]

Digging Deeper: Participant Comments on Policy Recommendations from the Survey

There were over 1200 detailed comments on the policy recommendations, provided by 28 respondents in response to a survey of the whole Working Group. Annex 8 provides all of the survey comments. In addition, comments by some participants on recommendations made after the survey are also available as part of the Working Group materials; see Annex 1. ***Together all of these comments provide a wealth of further insight into the recommendations and can be utilized by agency staff and others to help further understand and consider policy actions.***

[49] For purposes of this section, “strong convergence” was defined as a mathematical standard deviation of less than 0.6 across all Question #1 survey responses to a given policy recommendation, “broad convergence” was defined as standard deviation between 0.6 and 1.0, and “divergence of responses” as greater than 1.0.

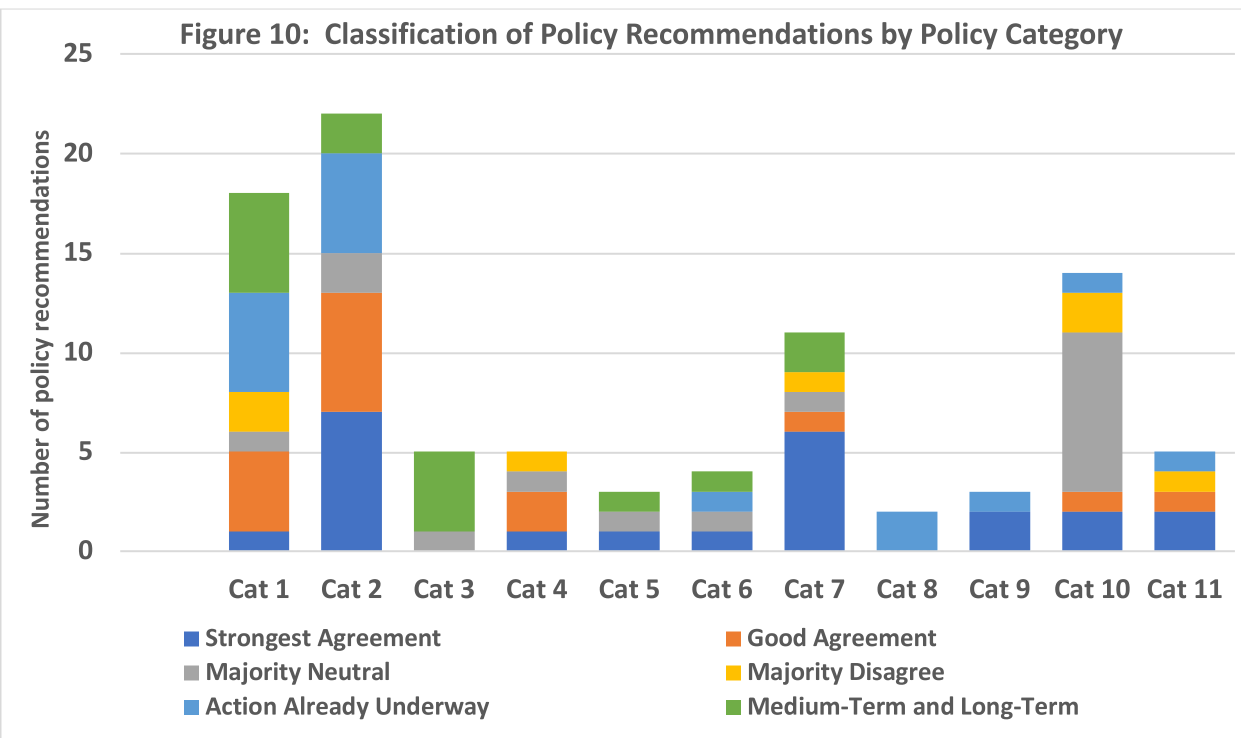
[50] “Majority neutral” also includes five cases where neutral is not an absolute majority, but rather total neutral responses are both greater than total disagreement response and greater than total agreement responses (1.06, 1.17, 3.01, 4.04, 7.01). These cases are noted in the text as also having a higher divergence of responses.

[51] There were 19 recommendations re-worded by the original submitters after the survey was taken: 1.10, 1.12, 1.16, 1.17, 2.02, 2.12, 2.16, 2.19, 2.20, 2.23, 4.03, 4.06, 6.01, 7.09, 7.11, 10.01, 10.04, 10.05, and 10.09. Re-wording was done mainly for clarification, so the policy substance of new wordings may remain similar to original wordings. The original wording of these 19 recommendations, upon which the survey results were based, is provided for reference in the Policy Recommendations Database linked in Annex 1. Most participants deemed that it was better to serve the needs of state agencies by accepting the updated wording at the risk of invalidating some of the survey results, recognizing that there was no time to repeat the survey for these recommendations. The classification of the 19 re-worded recommendations in this section is based on survey results for the original wording at the time of the survey.

Policy Recommendations Classifications by Category

The number of policy recommendations within each policy category and the classification of those recommendations are shown in Figure 10. Some characteristics of each category:

- More than half of Category 1 recommendations point to retail rate actions already underway or that should be further considered for the medium- and long-term. Rate applications not already in progress would be medium-term to allow time for submission, public review, and implementation.
- Most Category 2 recommendations on programs, procurements, and incentives had strong or good agreement, with a number also related to action already underway.
- Three-quarters of Category 3 recommendations on wholesale markets relate to the medium-term.
- Recommendations in Category 4 on studies and data have mostly good to neutral agreement.
- Although both Category 5 (bidirectional non-export/V2B) and Category 9 (market education) had fewer recommendations than other categories, they also received some of the strongest agreement.
- Category 7 on demonstrations and pilots has the highest share of strongest-agreement recommendations of any category.
- All Category 8 recommendations on technical standards relate to policy action already underway.
- More than half of the recommendations in Category 10 on inter-agency coordination are classified as majority-neutral, meaning most survey respondents were neutral on the relevance of these recommendations for scaling VGI.
- Category 11 on other programs and activities had mostly strong or good agreement.



Short-Term Recommendations with Strongest Agreement

There are 23 short-term recommendations with the strongest agreement (Table 8).[52]

Table 8. Short-Term Policy Recommendations with Strongest Agreement

Rec #	Policy Recommendation
1.07	Create an "EV fleet" commercial rate that allows commercial and industrial customers to switch from a monthly demand charge to a more dynamic rate structure
2.01	Require utilities to broadcast signals to a DER marketplace of qualified vendors (curtailment and load)
2.02	V2G systems become eligible for some form of SGIP incentives
2.04	Enable customers to elect BTM load balancing option to avoid primary or secondary upgrades, either if residential R15/16 exemption goes away, or as an option for non-residential customers
2.08	Consider coordinated utility and CCA incentives for EVs, solar PV, inverters, battery storage, capacity, and EV charging infrastructure to support resilience efforts in communities impacted by PSPS events
2.12	Allow V1G and V2G to qualify for SGIP to level the playing field with incentives for other DERs, but V1G would get less incentive compared to V2G based on permanent load shift logic
2.15	Incentive(s) for construction projects with coincident grid interconnection and EV infrastructure upgrade
2.17	Enable customers, via Rules 15/16 or any new EV tariff, to employ load management technologies to avoid distribution upgrades, and focus capacity assessments on the Point of Common Coupling
4.06	Use EPIC, ratepayer, US DOE, and/or utility LCFS funds for an on-going, multi-year program to convene VGI data experts to study lessons learned, quantify VGI/DER net value, fund new data sources, and study other topics
5.02	Pilot funding for EV backup power to customers not on microgrids, including goals for pilots in 2021-2022; utilities to consider feasibility of EVs for emergency backup in PSPS plans and resiliency solutions
6.07	Pilot funding for EV backup power to customers not on microgrids, including state-wide goals for at least 100 EVs by 2021 and 500 EVs by 2022; utilities to consider the feasibility of EVs for emergency backup generation in PSPS plans and resiliency solutions
7.03	Focusing on resiliency and backup application in workplace and multi-unit dwellings, leverage EPIC funding to pilot use-cases to understand and reduce costs and to streamline ease of implementation
7.04	Create pilots to demonstrate V2G's ability to provide the same energy storage services as stationary systems and let V2G systems participate in pilots for stationary storage
7.05	Special programs and pilots for municipal fleets to pilot V2G as mobile resiliency
7.07	Demonstration to define the means to allow aggregators, EV network providers, and charge station operators to dynamically map the capacity and availability of EVSE resources, using open standards
7.09	Use EPIC, ratepayer, USDOE, and/or utility LCFS funds ($50M) in many competitively bid large-scale demonstrations of promising VGI use cases to provide data needed to scale up VGI efforts (e.g., validate consumer acceptance, incentive levels, security, net value, and communication pathways)
7.11	Study to understand the impact on the distribution grid and generation system from EVs based on over ten existing or planned mandates from CARB and AQMDs to meet California's 2045 carbon neutral goal
9.01	Optimize CALGreen codes for VGI and revise to require more PEV-ready parking spaces and expand to existing buildings.
9.02	Create public awareness and education programs and materials on V2G systems and how to get them. This could particularly be focused toward government fleets
10.04	State agencies coordinate and maintain consistency on TE and VGI across the different policy forums with no duplication of regulation, clear roles and vision on VGI and priority on state TE goals over VGI
10.09	Incentivize use of multiple open standards for VGI communication, charging networks, cloud aggregators, and site hosts
11.03	Streamline permitting for charging infrastructure
11.05	Create Incentives for charging infrastructure for new public parking lot construction projects

[52] Tables 8-13 contain shortened text versions of the "policy action" associated with each policy recommendation. The full-text versions of all 92 policy recommendations, providing the full scope of the recommendation, along with a list of the extensive additional information available for each policy recommendation, are given in Annex 6.

Of these 23 short-term recommendations with strongest agreement, virtually all had broad "convergence" among all policy survey respondents. Such convergence means that all respondents agreed with each other – that there was a high degree of consistency among the responses. Recommendations 2.08 on coordinated incentives, 7.05 on municipal fleet pilots, and 9.02 on public awareness had particularly strong convergence. The exceptions to this pattern were 2.12 on V1G and V2G qualifying for SGIP and 7.11 on grid impact studies, which had weaker convergence than the others. For 2.12, four respondents strongly disagreed with the recommendation. Policy makers and any future working groups should examine the recommendations and comments to better understand the sources of the divergence.

While there was strong agreement for all of these recommendations, survey comments also pointed to considerations and questions that might need to be addressed, for example:

- Some policies might be considered medium-term rather than short-term, such as 2.01 on signaling a DER marketplace, 2.02 on SGIP incentives, 6.07 on pilots for microgrid-related solutions, and 7.07 on mapping EVSE resources.
- One comment also questioned how 2.01 on signaling a DER marketplace differs from existing DR programs.
- Mapping of EVSE resources is already part of the job and business models of aggregators (7.07).
- The perceived need for behind-the-meter load balancing varied widely (2.04)
- Some questioned whether it was appropriate to extend SGIP to VGI (2.02 and 2.12).
- Leveraging EPIC funding (7.03) will require collaboration between CPUC and CEC.
- Studies to understand grid impacts of TE are already underway (7.11).
- Open standards are possibly out-of-scope for the VGI Working Group to recommend (10.09).
- Public awareness (9.02) should be expanded beyond just V2G to also include V1G and the benefits of electrification in general, and should not be a stand-alone policy but part of a larger outreach, vehicle replacement and infrastructure planning effort.
- Permit streamlining (11.03) received the highest agreement level of all recommendations across all policy categories. However, some commenters were not clear about potential CPUC roles and what could be done. Energy Division staff noted that the Draft TEF (Section 10.3), identifies one possible answer—that utilities could potentially also provide training to support other types of PEV readiness activities beyond building code adoption and implementation, such as permit streamlining.

Policy Action for Medium- and Heavy-Duty Vehicles

The Working Group discussed what makes medium- and heavy-duty vehicles (MHDVs) distinct from light-duty vehicles (LDVs) in terms of VGI use cases and policy actions. While MHDV use cases were assessed distinctly from LDV use cases in answering PUC Question (a), some participants suggested that MHDVs are something of an "overlay" for policy rather than a distinct category of policy action. Policies for LDVs can also apply to MHDVs, including commercial rates, interconnection, and aggregation. However, the differences between MHDVs and LDVs also need to be understood by policy-makers, including a smaller number of customers with higher loads, rigid duty cycles, the special potential of school and commuter buses because of their duty cycle, clustering of large loads for MHDV charging, and the need to upgrade distribution system capacity to accommodate and accelerate MHDV charging. Some policy recommendations directly mention MHDVs, notably for programs related to school buses and transit vehicles. But most of the policy recommendations will apply to both LDVs and MHDVs.

Short-Term Recommendations with Good Agreement

There are 15 short-term recommendations with good agreement (Table 9).

Table 9. Short-Term Policy Recommendations with Good Agreement

Rec #	Policy Recommendation
1.01	Rate design for demand charge mitigation to be enabled by stationary battery storage coupled to EV charging
1.09	Allow customers with on-site solar and/or storage to utilize commercial EV rates
1.10	Improve Optional Residential and Commercial TOU rates designed to encourage EVs (e.g., whole house rate), fund outreach efforts on the rate, and set target to secure 60% level of participation
1.16	Expand the definition of eligible customer-generator under current NEM tariff option to include customers that own and/or operate EVs and/or EVSE with bi-directional capabilities
2.03	Establish "reverse EE" rebates (pay for performance?) for EVSE installations that build permanent midday load
2.13	Allow V1G (Smart Charging/Managed Charging) to be counted as storage for Storage Mandate
2.16	Encourage low-cost, multiple VGI communication control pathways and cloud aggregators and put to-be-determined VGI communication requirements on the cloud aggregators, not on the EVSE or EV
2.18	Incentivize multiple EVs using a single charging station in long-dwell AC charging locations to keep charging load spread across as many vehicles as possible
2.19	Create utility programs to site higher-level kW charging for commercial applications in the best locations to encourage high utilization using grid planning studies, routes, demographics & other tools
2.20	Consider funding opportunities and rate design reform for stationary batteries co-located with DCFC chargers
4.01	Establish a VGI Data Program to help gather, model, and analyze data related to VGI use-cases; prioritize the analysis of use-cases screened out by this Working Group due to data unavailability
4.03	Better understand the trend toward 10-19 kW home charging and explore long-term solutions to mitigate the impact (e.g. studies, pilots, task forces looking at incentives and disincentives)
7.06	Grant funding opportunities can be amended to provide "plus-up" funding for DER arrangements that optimize grid conditions
10.05	State agencies should recognize that stakeholder's specialized VGI staff resources are limited and avoid workshops and hearings on the same day, and hold no more than 2-3 VGI and TE events per month
11.04	Investigate ADA and other obstacles to charger installation at MUDs and some high-density C&I locations

Of these 15 short-term recommendations with good agreement, half had broad "convergence" among all policy survey respondents. Such convergence means that all respondents agreed with each other – that there was a high degree of consistency among the responses. The exceptions to this pattern were seven recommendations 2.03, 2.13, 2.18, 2.19, 4.01, 10.05, and 11.01, which had more pronounced divergence of responses. For some, a significant number of survey respondents disagreed with the recommendation, such as 8 respondents who disagreed with 2.03 on reverse energy efficiency rebates. Policy makers and any future working groups should examine the recommendations and comments to better understand the sources of the divergence.

Again, while there was good agreement for these recommendations, survey comments also pointed to considerations and questions that might need to be addressed, for example:

- Recent EV rate design changes have looked to reduce demand charges, which would reduce the potential benefit from stationary batteries for demand charge mitigation (1.01).
- Many details need to be worked out for 1.09 commercial rates for on-site solar.
- "Reverse EE" rebates (2.03) seems contrary to state mandates, may be better implemented as demand response or TOU, and may need better definition of relevance and market segments.
- Some comments questioned whether V1G can be considered "storage" (2.13).
- Need to clarify the eligibility of battery-backed DCFC for SGIP (2.20).
- Rules 15 and 16 should adequately address grid impacts of high-kW charging in residences, otherwise policy should accommodate and not stifle customer choice (4.03).
- ADA issues are unrelated to VGI and outside the scope of the Working Group (11.04).

Public Funds for VGI

Working Group participants noted that implementing policy recommendations in several of the policy categories will require public funds (i.e., budgetary funds, grants, or loans) and/or ratepayer funds (as approved in IOU rate cases). For recommendations in Category #2 "develop and fund government and LSE customer programs, incentives, and DER procurements," public funds and/or ratepayer funds are a primary source of funding, potentially along with private funds. These programs and procurements will typically be for commercially-mature or market-ready VGI solutions. Recommendations in Category #7, "fund and launch demonstrations and other activities to accelerate and validate commercialization," will likely also require public or ratepayer funds, and typically these funds are spent on solutions not yet commercialized or market-ready. Categories #4 and #9 may also require public and/or ratepayer funds, for data programs, studies, and analyses that can inform further decision-making and support market growth, and for market education and outreach.

Many participants believed that public funds should continue to support a wide range of VGI solutions and initiatives, including mature mass-market programs; innovative pilots and demonstrations; data programs, studies, and analyses; and education and outreach.

Short-Term Recommendations with Majority Neutral

There are 16 short-term recommendations with majority neutral (Table 10).

Table 10. Short-Term Policy Recommendations with Majority Neutral

Rec #	Policy Recommendation
1.06	The pricing signal received by the EV and that received by the EVSE should be aligned and consistent with one another and should incentivize and de-incentivize the same charging/discharging action
2.07	Create a strategic demand reduction performance incentive mechanism, include EVs as technology that can reduce and shift peak demand.
2.14	Prioritize, document and implement cost-effective use-case(s) for every transportation electrification plan, project, or program that is supported or subsidized by public funds, applied at commercial scale, and to be deployed within five years
3.01	Authorize new tariffs in CAISO ESDER Phase 4 that allow utilities to pay V1G aggregators to use managed charging to reduce the local distribution grid impacts of EV charging.
4.04	Perform detailed cost-effectiveness analysis for specific VGI use-cases in programs/measures that are ratepayer funded in order to quantify the impact on EV customers, ratepayers, utilities, and society
5.01	Bring automakers to the table to agree to allow limited discharge activity for resilience purposes to be kept under warranty if customers are willing to pay for upgraded bi-directional charging hardware.
6.03	Explicitly prioritize V2G use-cases for school buses with customer bill management to be included in the next cycle of PRP submissions by one or more LSEs, as well in the next phase of EPIC funding
7.01	Create pathways for TNC/rideshare drivers to reduce their costs by participating in utility programs and benefiting from make-ready infrastructure and charger rebates; by participating in state-funded programs like CALeVIP; and by securing direct access to utility rates when using public charging
10.02	Use the proposed Joint IOU VGI Valuation Framework (6 dimensions) and associated use-cases to reference, articulate, and communicate about VGI in policymaking across CA state agencies.
10.03	Public funding of VGI use-cases should prioritize initiatives, projects, and programs that involves formal collaboration between at least one LSE and at least one automaker or EV service provider.
10.06	Develop a Virtual Genset model and reference implementation pilot.
10.07	Avoid over-regulation of EVSE specifications
10.12	Establish a voluntary task force to convene on regular basis to discuss technological barriers, including potential recommendations related to interoperability, communication pathways, and protocols
10.13	Establish a voluntary task-force to convene on regular basis to discuss barriers related to retail market design, including potential recommendations
10.14	Establish a voluntary task-force to convene on regular basis to discuss barriers related to wholesale market design, including potential recommendations
10.15	Establish a voluntary task-force to convene on regular basis to discuss barriers impacting customer adoption and participation, including potential recommendation

Some examples of comments that point to the sources of such neutrality include:

- Many comments said the recommendation was not clear, more details are needed, it is not policy ready, and/or the problem addressed by the recommendation needs better definition: 1.06 on consistent price signals, 2.07 demand reduction performance incentives, 3.01 on CAISO ESDER tariffs, 6.03 on prioritizing use cases for PRP or EPIC, 7.01 on TNC/rideshare, 10.06 on a virtual genset model, and 10.07 on avoiding over-regulation of EVSE specifications
- Implementing cost effective use cases for every plan, project, or program (2.14) may not add value in every case, and requires coordination between many agencies
- Allowing limited discharge under warrantee (5.01) was seen as out of CPUC jurisdiction, the decision of individual automakers, and is not a clear-cut topic
- There were concerns about being too prescriptive for 10.02 on using the VGI Working Group use-case framework and 10.03 on prioritizing collaboration between LSEs and automakers

- Comments on 10.12, 10.13, 10.14, and 10.15 on volunteer task forces were mostly similar and supportive across all four recommendations, but many said this idea should be combined with other recommendations.

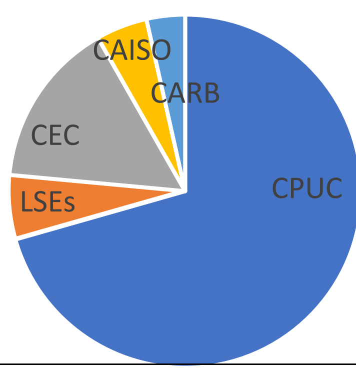
Of these 16 short-term recommendations with majority neutral, more than half had broad "convergence" among all policy survey respondents. Such convergence means that all respondents agreed with each other – that there was a high degree of consistency among the responses. The exceptions to this pattern were recommendations 1.06, 2.14, 3.01, 4.04, 5.01, 6.03, 7.01, which had more divergence of agreement than the others. Policymakers and any future working groups should examine the recommendations and comments to better understand the sources of the divergence.

Connecting the Dots: Lead and Supporting Agencies/Entities in Recommendations

Most of the 92 policy recommendations identify who the lead agencies/entities for implementing the recommendation would be, and some also identify agencies/entities in supporting roles.

- The CPUC is given as the lead agency in about two-thirds of the policy recommendations
- LSEs are given as the lead entities for five recommendations that all received strongest or good agreement: 1.15 on time-varying rates, 2.21 on performance-based incentives for building owners, 7.13 on quick approval of demonstrations, 9.03 on ME&O budgets, and 11.01 on demand charges for DCFC. Many other recommendations give LSEs supporting roles in carrying out programs and actions established or mandated by the CPUC or other organizations.
- The CEC is given as the lead agency for thirteen recommendations, relating to state-funded charging infrastructure, data and analysis, shared charging infrastructure, standards and requirements for buildings, EPIC funding, demonstrations and pilots, and public awareness and education programs. All but one (10.07 on over-regulation of specifications) received strongest or good agreement.
- CAISO is given as the lead entity for four recommendations: 3.01 on ESDER tariffs, 3.03 on real-time and ancillary markets, 3.04 on pathways for V2G participation in day-ahead and RA system services, and 3.05 on capacity-only system services. The last three are all medium-term recommendations with strongest or good agreement. CPUC is given as the supporting agency for three of the four recommendations, consistent with supporting the outcome where wholesale market rules are aligned with the highest-value opportunities for VGI.
- CARB is given as the lead agency for three recommendations: 2.24 on LCFS smarting charging, 7.02 on LCFS credits, and 11.02 on a shared benefit structure for LCFS.

Distribution of Lead agency/entity across all 92 recommendations



Short-Term Recommendations with Majority Disagreement

There are 7 short-term recommendations with majority disagreement (Table 11).

Table 11. Short-Term Policy Recommendations with Majority Disagreement

Rec #	Policy Recommendation
1.02	EV drivers across all sectors must be guaranteed direct access to their utilities' cost-competitive time-variant (e.g. TOU) rates; utilities must be allowed the option to own and/or operate at least a portion of the charging stations across all sectors so that their rates are directly available to EV drivers
1.05	Price signals received by EV customers should be relatively consistent (not necessarily identical) at a given time of day, across different sectors and price-setting entities; at the very least, different price-setting entities should agree on the time window where "off-peak" rates apply
4.02	Any Level 2 EVSE sold within the next two years should be capable of responding to external event or price signals, or user-defined criteria, and support OCPP, OpenADR, or IEEE 2030.5.
7.02	Improve the allocation of LCFS credits such that EVs with higher vehicle-miles earn higher credits, claiming credits is streamlined for EV drivers or their agents, and most credits are channeled back to driver/agent
10.10	A ML EVSE or charging station must be capable to provide energy services and may provide regulation services, and must support OCPP or an equivalent standard that supports an external energy management system for grid interactions
10.11	A HL Charging Station must provide energy services and must be capable of providing regulation services
11.02	Institute shared benefit structure for LCFS or similar funding between host site and EV driver/operator/owner

Some examples of comments that point to the sources of such disagreement include:

- Questions about whether utilities should own charging infrastructure and how that can be justified (1.02)
- Each LSE has its own cost recovery structure and there are limits to rate harmonization (1.05)
- Equipment requirements for EVSEs may seriously hinder the industry (4.02)
- It may be difficult for LCFS to cover EV drivers and may be difficult to administer (7.02)
- Concerns about relevance, technical standards, over-specification, and whether equipment and hardware specifications are in-scope for the Working Group, for both 10.10 and 10.11 on medium-level and high-level EVSE charging stations.
- Some said a shared benefit structure for LCFS is not really a VGI policy (11.02)

Of these recommendations, two had broad “convergence” among all policy survey respondents as to their common disagreement – 10.10 and 10.11. The other recommendations -- 1.02, 1.05, 4.02, 7.02, and 11.02 -- had high divergences of agreement and disagreement even as the majority disagreed with the recommendation. Policy makers and any future working groups should examine the recommendations and comments to better understand the sources of the divergence.

Connecting the Dots: Policy Recommendation Overlaps and Connections

Many of the 92 policy recommendations overlap with each or are connected to each other. Working Group participants, in policy survey comments (Annex 8) and in further discussions noted these overlaps and connections and recommended that related policies be considered together. Examples of these overlaps and connections include:

- Submetering is addressed by 1.04, 1.12, and 8.02
- Net metering (NEM) is addressed by 1.16 and 2.16
- Cost-effectiveness and cost-benefit analyses are addressed by both 4.01 and 4.04
- Stationary batteries co-located with EV charging is addressed by 1.01, 2.20, and 7.06
- Charging infrastructure funded by the CEC or by utilities and other LSEs is covered by 2.05 and 2.06
- Market participation of V2G resources is addressed by 3.04 on system services from V2G and 3.07 on participation options for V2G
- Backup power and resiliency (vehicle-to-building V2B and vehicle-to-microgrid V2M), including pilots and incentives, are addressed in different ways by 2.08, 5.02, and 5.03
- Extending SGIP to VGI is addressed by 2.12 and 7.04
- Incentives for charging infrastructure in new construction are addressed by 8.01, 9.01, and 11.05
- Four recommendations relate to opening up new value streams that can be captured by EV energy management systems (EV EMS), and also provide an additional type of "incentive" or benefit-enabler: 2.04 on BTM load balancing to avoid distribution system upgrades, 2.17 on customer load management to avoid or defer utility distribution upgrades, 2.22 on non-wires alternatives to similarly avoid or defer utility distribution upgrades, and 2.18 on multiple EVs sharing a single charging station

Policy Recommendations Related to Policy Action Already Underway

There are many policy actions and venues already underway related to VGI. The Working Group took note of a full array of policy actions already underway that related to its policy recommendations. In particular, there are 16 recommendations flagged as relating to "policy action already underway" by the CPUC Energy Division (Table 12).

However, even though action is already underway related to a policy recommendation, the Working Group recommends that all such policy recommendations still be considered in strengthening or extending any existing or planned policies, and that other proceedings that may be addressing these policies take note of these recommendations.

This is underscored by the fact that almost all of the 16 recommendations in Table 12 have strongest or good agreement. For example, two policies related to submetering, 1.12 and 8.02, have good agreement, indicating that the CPUC may wish to further consider sub-metering policy development. There is also strongest agreement for 1.13 on time-variant charging rates, 2.09 on pilots, 2.11 on dealer incentive programs, and 9.03 on ME&O budgets. Two recommendations, 2.24 on LCFS smart charging and 6.04 on NEM tariffs, received "majority neutral" classifications.

Many others of the 92 recommendations put forward by the Working Group may also relate to actions already underway and Table 12 is by no means comprehensive. The detailed information on policy recommendations (Annex 6) contains further notes on related proceedings and other venues. Table 12 only represents partial information collected from participants and comments by CPUC Energy Division staff. Further comments by Working Group participants on other actions already underway and the need to strengthen actions already underway are linked in Annex 1.

Table 12. Recommendations Related to Policy Action Already Underway

Recommendations	CPUC Energy Division Staff on Action Already Underway
Establish EV TOU rates that don't require separate metering or submetering (1.04) If dynamic rate is unavailable, increase the differential between standard and EV TOU off-peak charging rate (CPUC comment: already adopted) (1.08) Develop a standard implementation guide for utilities to provide real-time price and event (control) signals to EVSEs, Charging Station Management Systems (CSMSs) and EV drivers (1.11) Retail EV charging rates should reflect cost of generation, delivery, GHG, and other relevant value streams; all EV charging rates should be time-variant, starting with simple TOU rates and then enabling optional alternatives such as dynamic rates (1.13) Reduce or eliminate demand charges for DCFC, but scale up with utilization to create more demand-responsive rate (11.01)	Multiple rate cases are already considering these policies, or some policies are addressed through recently implemented rates or proposed commercial EV rates under review
Re-examine or use existing AMI alternative approaches to submetering in residences for EVs, DERs and demand responsive appliances to lower cost and level the playing field for DERs (1.12) Finalize submetering protocols/standards to increase accessibility to more favorable EV TOU rates (8.02)	These are already being addressed through ongoing submetering work in the DRIVE OIR
Require managed charging capability in utility customer programs, incentives, and DER procurements (2.05)	All IOU programs currently require load management participation for customers to be eligible
Require all government-funded charging infrastructure to have smart functionality (2.06) Leverage existing pilots to identify bottlenecks for increasing deployment and reducing costs. Encourage utilities and other LSEs, in partnership with private entities, to establish dedicated programs for school bus charging (2.09)	These are already a goal in the Draft TEF
Create an EV Dealership VGI upfront incentive program whereby utilities can reward dealers for installing or enabling VGI functionality at point of sale (2.11)	SDG&E and Plug-in America are already testing this in a pilot and results are pending and other similar testing of this concept will occur as more dealers sign up to participate in the LCFS upfront rebate program

Align LCFS smart charging framework with IOU TOU rates (2.24) **	Aligning the LCFS incremental incentives with IOU TOU periods is already a requirement in CARB's regulation. The smart charging pathway is currently based on the CPUC avoided cost calculator. **
Drastically simplify NEM tariffs and streamline NEM applications for EVs; and encourage better communication of EV TOU and NEM rates to the general public and businesses (6.04)	There is already a NEM 3.0 effort underway, and multiple efforts to streamline/simplify EV rates to ensure they can be combined with solar-plus-storage.
Incentives for Title 24 new construction – residential multi-unit dwellings and some commercial and industrial parking facilities (especially workplace and large destination) (8.01)	Consistent with a CPUC staff proposal; new construction incentives are addressed in Section 5 of the Draft TEF
Utilities develop coordinated ME&O budgets through transportation electrification plans, to inform EV customers of the lower cost of fueling EVs using dynamic rate options and other VGI opportunities (9.03)	Every IOU program budget already includes ME&O, and the draft TEF proposes a new aligned ME&O effort. The Draft TEF section 11.2 mentions TOU rate education, and this could be re-focused to provide direction and alignment. Non-IOU ME&O is also stated in draft TEF.
Prevent policies that make VGI a primary goal over the needs of drivers or CARB and AQMD mandates to support 2045 carbon neutrality and 2030 air quality requirements; don't add net cost to TE end users or hinder EV adoption or equity goals due to VGI and fund efforts to study and monitor this issue (10.01)	This is a goal for all CPUC programs approved for IOU ratepayer funding,

** Recommendation 2.24 on LCFS smart charging falls under the jurisdiction of CARB as the lead agency. The inclusion of this recommendation as related to policy action already underway is based upon CPUC Energy Division staff comments confirmed by CARB.

Digging Deeper: Policy Strategy Tags

Each of the 92 recommendations has one or more "policy strategy tags" that the Working Group assigned. This mapping of tags can show the collective contribution of policies to achieving distinct policy strategies and goals. Annex 7 shows which recommendations in which categories are associated with 16 different policy strategies and goals.

Medium- and Long-Term Policy Recommendations

There are 15 recommendations that address the medium-term (2023-2025) or long-term (2026-2030), given in Table 13. All of these are either strongest agreement (1.15, 1.18, 3.03, 5.03, 7.13) or good agreement, with just one classified as majority neutral (1.19 on performance-based ratemaking).

Table 13. Medium-Term and Long-Term Policy Recommendations

Rec #	Policy Recommendation
Medium-Term	
1.15	Prompt CPUC approval of time-varying EV rates applications
1.17	In addition to an EV export bill credit (under NEM or another framework), a supplemental credit should be considered for environmental component, e.g., based on SGIP GHG signal to determine marginal emissions rate
1.18	Establish voluntary "critical peak pricing" tariffs for non-residential charging that offer reduced TOU rates except during event-based flex alert or critical peak periods, while providing significantly increased on-peak prices
2.21	Provide a performance-based incentive to temporarily provide grid services, for building owners or EVSP providers who recruit a certain fraction of EV drivers to opt in, implemented as a long-term contract through procurement
2.22	Issue non-wires alternative competitive procurements (RFOs) targeted to EVs/EVSPs that can limit demand during peak times
3.03	Enable aggregations of EVs on managed charging to participate as resources in real-time energy markets and ancillary services market
3.04	Need clarity and conclusive decision on what pathway (PDR vs. NGR) will enable V2G resources to offer Day-Ahead Energy and RA System services, and clarity on PDR timeline and roadmap if PDR is the chosen pathway
3.05	Alternative PDR participation model or new capacity-only designation for resources to provide ancillary services only, to allow BTM charging to participate, single site or aggregated
3.07	Coordinated effort by state agencies and IOUs and other LSEs to establish market rules and participation options for separately metered V2G customers.
5.03	Develop standards and requirements for buildings which will support the use of the EV's main power batteries for customer resiliency
7.13	Create a mechanism which allows for quick approval of demonstrations for technology and for determining market interest
7.14	Pilots for shared charging infrastructure for commuter-based fleets, both public and private, including transit commuter buses and company fleets and shuttles.
Long-Term	
1.19	Institute performance-based ratemaking that includes both capital expenditure and operational expenditures, to encourage more efficient EV-related distribution build-out
1.20	Create tariffs specific to medium/heavy duty vehicles, fleets, and rideshare
6.11	Coordinate the development of interconnection and technical standards with the VGI Working Group effort

As the CPUC and other agencies and entities move forward with the short-term recommendations, and also begin to address the mandates of SB 676, these medium- and long-term recommendations will be relevant. The Working Group's suggested next steps in this report's Conclusion section address this further.

SECTION C. PUC QUESTION (C): HOW DOES THE VALUE OF VGI USE CASES COMPARE TO OTHER STORAGE OR DERs

The Working Group did not provide a direct answer to PUC Question (c), "how does the value of VGI use cases compare to other storage or DERs," but does offer guidance on how to complete this work going forward.[53]

Discussions revealed that this is a complex topic which can require a great deal of analytical resources and expertise. To answer the question quantitatively in the manner originally envisioned would require rigorous cost-benefit analysis. Due to time, data, and expertise constraints, the Working Group did not perform cost-benefit or cost-effectiveness analysis of either VGI use cases or other DER use cases. The Working Group also faced limitations in getting private-sector cost information and could only assess costs on a relative basis. And given that the Working Group was comprised entirely of volunteer participants, many of whom did not have direct expertise in storage and other DERs, there was insufficient time, volunteer availability, and expertise to consider the value of storage and other DER use cases.

Instead, the Working Group recommends that the PUC address this question through further efforts with the necessary expertise, for both VGI and other DERs. These further efforts can recognize and incorporate the wealth of work and perspectives on VGI use cases produced by the Working Group (see Annex 1 for the materials produced by the Working Group).

<u>Guidance on How to Compare VGI with Other DERs</u>

The Working Group suggests that further efforts consider three approaches to comparing VGI with storage and other DERs: quantitative cost-benefit comparisons, qualitative comparisons, and use-case-based comparisons.[54] Each of these approaches has its merits and difficulties, as noted in Table 14. The Working Group also identified some potential resources and references related to costs, benefits, and value comparisons that could be considered in further efforts, although these resources were not reviewed or assessed (see Annex 3).

Table 14: Recommended Approaches for Comparing VGI with other DERs

Approach	Merits	Difficulties
1. Quantitative cost-benefit comparisons	• Provides numerical comparisons of value • Can also incorporate the value of managed charging (including direct and indirect, V1G and V2G) vs. unmanaged charging • Satisfies direction from CPUC in DRIVE OIR; complies with CPUC D.19-05-019	• Cost data difficult to obtain or not available; may require demos or pilots to provide data • Potential disagreement over the methodologies and assumptions employed in conducting numerical comparisons • Defining VGI cost additionality relative to baselines

[53] The Working Group notes that VGI is considered as one form of DERs and is defined as a DER in Assembly Bill 327.
[54] See D.19-15-09, CPUC decision guiding cost-effectiveness evaluation of DERs.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF

2. Qualitative comparisons	• Can provide insight for policy making in supporting VGI and in having the value of VGI complement the value of other DERs • Can also give insights into the first and third approaches	• There are many possible scenarios to compare, and the results of one scenario cannot necessarily be compared to the results of another scenario • Does not comply with CPUC direction in DRIVE OIR that VGI be compared to other DERs; does not comply with CPUC direction on comparative analysis in D.19-05-019
3. Use-case-based comparisons	• Leverages the use-case work of the Working Group and potentially allows a simplified apples-to-apples comparison • Can provide insight for policy making in supporting policies associated with specific use cases • Can also be quantitative with similar merits and difficulties as the first approach	• Does not comply with CPUC direction on comparative analysis in D.19-05-019 • Lack of cost data to support comparisons; may require demos or pilots to provide data, or relative cost comparisons as was done by the Working Group for VGI use cases • There are many distinct VGI use cases and comparing on an individual basis can be time-consuming • Requires developing the equivalent DER use cases to match VGI use cases, which the Working Group has not done • What metrics would be measured? What does a positive or negative comparison look like?

1. Quantitative cost-benefit comparisons. A variety of potential studies are available that could address quantitative comparisons; see Annex 3. However, the Working Group did not assess or endorse any quantitative studies, given time and expertise limitations. It is not clear the extent to which existing studies provide cost-benefit comparisons of VGI with other DERs that would be relevant to California. Thus, even identifying and selecting such studies will be a significant effort. One next step would be to establish the criteria that should be used for selecting, assessing, and utilizing such studies, including the relevance to California.

Participants noted a number of methodological issues that would need to be considered and addressed in conducting quantitative cost-benefit comparisons. On the costs side, participants noted there is a scarcity of publicly-available cost information, underlined by the difficulties and time constraints that the Working Group faced in getting private-sector participants to share cost information during the process to score use cases on costs, benefits, and ease of implementation (see Section B). Given more time, additional data would potentially have been available. There is a continuing need to first develop better cost information, such as from large-scale demonstrations and competitive solicitations, and to further identify existing public sources of cost data. This may be a case when "an ounce of commercial activity would be worth a pound of research."

The definition of "costs" itself is not straightforward, considering the different costs (and prices) to different parties involved in a particular use case, such as equipment and vehicle providers, customers, electricity providers, and aggregators (for further discussion see Annex 1 links to materials on cost methodologies). Some participants also highlighted the need to better define the incremental or additional costs associated with VGI, as distinct from costs that would otherwise be incurred anyway in owning and operating EVs, such that true "apples-to-apples" comparisons of VGI costs and benefits can be made.[55]

On the benefits side, there is a need for a consistent set of assumptions for the benefits from the same service utilizing VGI compared to other DERs. The benefits of VGI can also come from complementary roles with other DERs, in which the value of the other DERs may also increase. Such complementary roles need further understanding when making comparisons between VGI and other DERs.

Further, there is considerable scope for determining the best metrics for reporting on cost-benefit comparisons of VGI with other DERs, including such metrics as gross bill savings, net customer savings, customer benefit/cost ratio, and other standardized cost-benefit metrics including those that address ratepayer impacts and societal costs. Some participants of the Working Group said some metrics should be prioritized over others.

2. Qualitative comparisons. A qualitative comparison of a VGI use case with another DER use case can highlight the uniqueness and potential benefits of VGI in both complementary and substitution roles relative to other DERs. Qualitative comparisons can be developed in terms of characteristics such as location, resource availability, market participation and pricing, application, size/scale, ownership, capital investment, lifetimes of equipment and contract periods, and environmental benefits. For example, a stationary battery for a residential or commercial building might be compared with an EV for personal use along these dimensions, with the following *possible illustrative* conclusions:[56]

- Location and resource availability: a stationary battery may have comparatively greater availability but only for a fixed location, while EVs may have more limited availability but offer many variable locations from which to provide grid services needed at a given time and location.
- Market participation: both EV and stationary battery are subject to retail pricing but there are differences in how they can participate in the wholesale market
- Size: an EV battery is typically larger than a residential stationary battery, while the opposite can be true compared to a stationary battery in a commercial building
- Scale: EV batteries must typically be aggregated to a larger scale for participation in wholesale markets and do not need to be separately metered, while commercial batteries may participate individually and must be separately metered.
- Capital investment: EVs don't have to be purchased or leased by distribution utilities and LSEs to obtain the benefits of storage for their distribution grids and load-serving needs, in contrast to utility-scale stationary storage owned by distribution utilities and LSEs.
- Lifetimes of equipment and contract durations: an EV will typically have a lifetime of 5-10 years and contract durations as short as one year, while a stationary battery will typically have a lifetime of 10-20 years and longer-term contractual periods.

3. Use-case-based comparisons. Some storage and other DER use cases could be characterized along some of the same six dimensions of the use case assessment framework that Working Group employed to assess VGI use cases. These dimensions include Sector, Application, Type, Approach, Resource Alignment, and Technology (see Section B). Participants noted in particular the potential overlap of the

[55] See D.19-15-09, CPUC decision guiding cost-effectiveness evaluation of DERs.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF
[56] Annex 1 gives a further resource by Sumitomo provided to the Working Group as an example of a qualitative comparison.

Sector, Application and Approach (direct vs. indirect) dimensions of VGI use cases with other DER use cases. If VGI and other DER use cases can be put into the same framework, then storage and other DER use cases could potentially be scored (by DER experts) in the same manner that the Working Group scored VGI use cases. The resulting scoring of both VGI use cases and other DER use cases could be compared on a similar basis, for benefits, costs, and ease of implementation. Such comparisons should:

- Configure the comparisons to compare “apples-to-apples” as much as possible
- Compare based on which DERs provide which grid services (i.e., for the same application)
- Compare by sector—home, fleet, workplace, public, large MUD, etc.; and for different viewpoints—customer, ratepayer, utility, CCA, etc.
- Identify which VGI use-cases have higher vs. lower potential benefits for utilities & ratepayers, how low technology costs would have to be to enable those use-cases, and how much value would arise from spending a similar amount of customer/ratepayer dollars for other DERs that can provide the same services.
- Map out dimensions of sector-based “complex” or “multi-use application” use cases (i.e. one sector, many applications) from the perspective of existing utility and other LSE DER programs – such as NEM, SGIP, EE, CPP/BIP. See which use cases from the VGI Working Group map to which use cases supported by these other DER incentive programs.

Such comparisons between VGI use cases and other DER use cases providing the same or similar services can illuminate trade-offs between the two options for a decision-maker, as well as provide a bottom-up understanding to complement top-down market-based comparisons.

Some Other Viewpoints

Some Working Group participants disagreed with the emphasis on quantitative comparisons and cost-effectiveness for VGI implied by PUC Question (c). Rather, they favored a focus on PUC Question (b) and continuing to focus on policies for “leveling the playing field” for VGI, and understanding and prioritizing the highest-value activities and policies for EV adoption and managed charging for both near-term and long-term.

Some Working Group participants also emphasized pursuing further comparative analyses of scenarios with managed charging via VGI, compared to scenarios with continued unmanaged charging. In their view, the most informative and relevant comparisons are to be made between scenarios with VGI (containing direct managed charging and/or adoption of time-varying rates) and counterfactual scenarios of unmanaged charging without VGI. Here again, VGI value can be discovered or determined based on analytical cost-effectiveness assessments or market-derived cost-competitiveness information.

CONCLUSION AND NEXT STEPS

The VGI Working Group is proud to present this report and associated materials. Working Group participants were motivated by a conviction that VGI affords many potential benefits. Many opportunities to realize these benefits are available today and will grow rapidly as EV adoption expands, as shown by the extensive work completed by the Working Group on use case assessment and policy recommendations. This work provides a solid foundation for the next stages of VGI in California.

The high degree of cooperation and collaboration achieved–among over 85 organizations and individuals participating voluntarily during the ten-month course of the Working Group—also demonstrates that VGI is a unique and effective convening umbrella or venue for fostering collaboration between the electric power and EV/charging sectors, and among many types of industry, government, advocacy, research, and utility and CCA stakeholders.

The next steps beyond this report for California state agencies, the California ISO, utilities, community choice aggregators and other load-serving entities, and other VGI stakeholders could include:

Policy actions

- Continue inter-agency efforts to advance VGI understanding, piloting, and large-scale deployment, leveraging private and public funds for that effort. Efforts should be inclusive and cover a wide variety of VGI solutions at different levels of maturity and readiness.
- Prioritize actions and resources to ensure robust and streamlined implementation of the 92 policy recommendations produced by the Working Group, taking into account the 1200-plus detailed comments generated by the Working Group on these recommendations.
- Use the policy recommendations and other materials from this report to inform and motivate state agency action on several ongoing VGI issues, including V2G interconnection, submetering, VGI customer programs, and EV rate design.
- Map the use cases put forth by the Working Group onto existing and planned California policies and programs for transportation electrification, and identify gaps in policies and programs for addressing priority use cases.
- Further explore and understand the implications and relevance of this report for the development of the Transportation Electrification Framework (TEF).
- Use the policy recommendations and other materials from this report to inform development of the strategies and quantifiable metrics called for by SB 676.

Interagency coordination and convening

- Convene a further working group or other venue composed of both VGI and DER experts and industry representatives, to conduct comparisons of VGI use cases with other DER use cases, perhaps starting with “net value” analysis on the use cases put forward by the Working Group.
- Coordinate and fund an inter-agency effort to conduct the demonstrations and pilots recommended by the Working Group based on collaborative and coordinated actions across agencies.

Further analysis

- Assess customer interest, acceptance, and retention, and what is required (and associated costs) to get customers to participate in VGI programs (e.g., incentives, marketing, dealership education).
- Identify and obtain publicly available data on VGI costs, as well as baseline data on driving and charging patterns relevant to different use cases.
- Conduct cost-effectiveness tests and cost-benefit analyses as part of further answers and understanding of PUC Question (a) on use case value and PUC Question (c) on comparisons with other DERs, and as part of assessing impacts of pilots, programs, and policy recommendations.
- Building on the single-application use cases defined in Section A, further define and explore "complex" or "multi-use application" (multiple application) use cases that can "stack" or combine the values of multiple services and benefits for single use case.
- Undertake a focused and detailed review of the results from the use-case value scoring exercise, to identify next steps for understanding VGI net benefits, with emphasis on use cases that were not scored but could provide value in the medium- and long-term.

California can become a global leader in transportation electrification and VGI implementation, but only with concerted and committed efforts to improve regulatory policies and expand market opportunities. The Working Group showed that there are many potential VGI use cases that can provide value, and that the potential market for VGI solutions is diverse and interwoven across a broad swath of the transportation and power sectors. Given the use case assessment work performed by the Working Group, it appears that the work of developing markets for VGI solutions will demand persistent action for the next several years. California should take an inclusive and collaborative approach to VGI opportunities given the evolving nature of the regulatory and market landscape.

The Working Group, consisting of organizations voluntarily contributing their limited time and resources, commends this report to the leaders of the California ISO, CEC, CARB, and CPUC. We ask for thoughtful consideration of these recommendations and a timely response to this plea.

GLOSSARY

Aggregator – an entity that aggregates, coordinates, and controls multiple DERs to provide energy services as an aggregate of the individual DER capacities and capabilities.

Ancillary Services – energy services that do not directly feed load, but keep a power system functional; e.g. – voltage and frequency regulation, reactive power injection.

Behind the Meter (BTM) Storage – energy storage systems that operate "behind the meter," i.e not on the transmission or distribution system, but onsite with an electricity customer.

Curtailment – the intentional reduction of output of a renewable energy system below what it could have otherwise produced.

Demand Charge – a charge for the maximum capacity that a customer uses during a billing period.

Demand Response – a strategy wherein loads are taken offline or curtailed in order to lower system demand. A variety of controls are possible, from passive time-varying rates to direct and active commands from the load-serving entity or from an aggregator.

Distributed Energy Resource – energy resources - including small scale power generation, energy storage, energy efficiency, energy demand response, and electric vehicles – that operate onsite at a customer's premises or business, or on the distribution level of the power system.

Distribution Upgrade Deferral – any investment that allows for the delay or nullification of planned system upgrade investments, such as local DERs or customer energy management systems.

Electric Vehicle Service Equipment – any equipment that is used directly to charge electric vehicles, or is used to connect vehicle chargers to the power grid or other energy resources.

Electric Vehicles – Vehicles that solely employ electric motors and batteries, or hybrid plug-in vehicles that combine electric motors and batteries with internal combustion engines that can be charged from an external power source. Also called plug-in electric vehicles (PEVs).

Electricity Service Providers – any load-serving entity (LSE) that offers electric service to customers within a given service territory

Grid Interconnection – the point of connection between a DER and the distribution grid.

Inverter – a device that converts DC (battery) power to AC (grid) power and vice-versa.

IOUs – Investor Owned Utilities are Load Serving Entities (LSEs) that fall under the regulatory jurisdiction of the CPUC, as compared to other LSEs such as community choice aggregators (CCAs) and municipal-owned utilities (MOUs) that do not.

Load Serving Entities – entities that have been granted authority pursuant to state or local law or regulation to purchase wholesale electricity and directly serve electricity to retail customers; investor-owned and municipal utilities, as well as electric co-ops and community choice aggregators are load serving entities in California.

Managed Charging – coordinated shift/modulation of time or level of EV charging or discharging in response to a variety of possible signals, both passively (indirect use cases) and actively (direct use cases); examples of signals are time-varying prices and signals of grid conditions; includes unidirectional V1G and bidirectional V2G and V2B/V2H as well as indirect and direct control approaches.

Microgrid – an integrated localized grid system that can operate independently from connection to the larger grid. Microgrids can vary in size from single-home scale to a variety of community scales.

Peak Period - the period in a given time frame at which the power system is experiencing its peak demand.

Peak Demand – the greatest level of energy needed within a given time period.

Point of Common Coupling – the point where the generating facility's local electric power system connects to the electrical company's electric system, such as the electric power revenue meter or at the location of the equipment designated to interrupt, separate or disconnect connection to the grid

Resiliency – the ability of the grid to operate during potential disruptions; and also the ability to provide local or customer-level solutions if the grid undergoes an accidental or intentional outage and is not available.

Resource Adequacy – a set of regulatory and planning constructs used to ensure that there will be sufficient generating resources available to serve electric demand under all but the most extreme conditions

Submetering – the measurement of electricity consumed by a specific load, such as an EV, separate from or as part of a customer's overall metered account.

Time-Varying Rates – an energy tariff wherein the price of energy varies depending on the time of day; can be static time-of-use (TOU) rates fixed for specific times of the day, or dynamically varying.

Uni-Directional / Bi-Directional Grid Interactions – EV use cases are defined by the flow of energy between the EV and the source powering it. Uni-directional grid interactions are situations in which power flows from the grid to the EV. Bi-directional grid interactions specify situations in which power can flow from the grid to the vehicle and vice-versa.

Use Case – use cases represent the different ways in which EV charging can be integrated with the grid (or home/local power system) to provide value. Use cases help articulate how value streams can flow to different stakeholders, including EV owners and fleet managers, workplaces and other charging site hosts, charging service providers, utilities and CCAs, ratepayers, and grid operators.

Value Stacking – obtaining multiple value streams and services, for example both customer bill management and system day-ahead energy, from a given VGI use case.

End of Attachment A

Attachment B

ANNEX 1: MATERIALS PRODUCED BY THE VGI WORKING GROUP

All materials produced by the VGI Working Group are listed and linked individually below and are also available on this web page: https://gridworks.org/materials-produced-by-the-vgi-working-group

Final Report

- Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group
- Final Report Annexes

Methodology Development

- VGI Working Group Stage 2 Report
- Updated V2 IOU Joint Proposal on Use-Case Assessment Methodology
- IOU Perspective on VGI Use-case Benefits and Costs
- Workshop 9/26 Methodology Issues Brainstorming Notes

Use Case Development, Submissions, Screening, and Scoring

The Use Case Assessment Database is an on-line viewable Airtable containing the use case screening and scoring compilations and summaries from which all use case assessment information in this report was derived. This database has the following tables, which are linked here as Excel files:

- LDV use case scoring
- MHDV use case scoring
- Scoring comments
- Screening results
- Use case submissions
- Use case master list

In addition to the database, the following documents and spreadsheets were produced by the Working Group:

Details on submission, screening and scoring process and results:

- VGI Working Group Stage 3 Report

Templates for submissions:

- Subgroup B use case submission template
- Subgroup B screening template
- Subgroup B LDV scoring template
- Subgroup B MHDV scoring template

Final results of submissions:

- VGI Master list of use case submissions (10/28)

Screening results and use-case-specific comments on screening:

- Pile A consensus pass final screening results (12/8)
- Pile B fail final screening results (12/8)
- Pile C disputed pass final screening results (12/8)

Screening overview comments and rules:

- Team 3 screening comments/rules (10/31)
- Team 6 screening comments/rules (11/04)
- Team 8 screening comments/rules (11/04)
- Team 9 screening comments/rules (10/31)
- Team 10 screening comments/rules (11/04)
- PG&E-SCE-Enel X screening comments/rules (11/12 revised)
- Consensus assumptions from 1/22-1/23 workshop

Scoring results and use-case specific comments on scoring:

- LDV scoring compilation and summary (revised 1/13)
- MHDV scoring compilation and summary (12/26)
- LDV and MHDV scoring comments (12/26)

Ranking or analyzing the use cases:

- Honda Value Metric, Inputs to CPUC VGI Working Group Question #1 (1/20/20)
- Nissan VGI Scoring Data Perspectives
- Karim Farhat scoring analysis / Prime subsets
- SCE Interactive Scoring Display Tool

Other:

- Development of Market Analysis and Use-Cases for Medium & Heavy-Duty Vehicle-Grid Integration Meredith Alexander et al, CALSTART and UCS
- Ratepayer Impact Benefits Category Ed Burgess, Vehicle-Grid Integration Council
- Use Case Scoring Results – LDV VGIC Workshop #4 Presentation
- E3 California Framework for Grid Value of VGI, 4/12/2019
- Fermata use cases providing value

Policy Recommendations and Survey

The Policy Recommendations Database is an on-line viewable Airtable containing the following information. Each of the tables in this database is also available as an Excel file via the links below.

- Policy recommendations
- Policy survey responses
- Policy survey results
- Policy survey comments
- Added comments on policies

- Policy survey respondents
- Policy strategy tags
- Policy short versions

Supplementary Materials on Policy Submitted by Participants

Note: all policy recommendation materials submitted by participants were incorporated into the Policy Recommendations Database linked above. In addition, some participants submitted supplementary PDF documents related to policy recommendations:

- CalETC supplementary document on policy recommendations
- Energy innovation supplementary document on policy recommendations
- Amzur supplementary document on policy recommendations
- Fermata supplementary document on policy recommendations
- The Mobility House supplementary document on policy recommendations
- ENGIE Impact policy survey analysis

Working Group Participant Submissions on Comparison of VGI Use Cases with Other DER Use Cases

Note: these submissions are neither endorsed nor reviewed by the Working Group

- CEC response on importance and benefits of VGI
- VGIC response on importance of VGI
- SBUA response on importance of VGI
- CESA's informal comments on the VGI-DER value comparison questions
- VGIC PUC Question C Big Picture Response
- ENGIE Impact and DER Comparisons Team, Addressing PUC Question C
- E3 Vehicle Grid Integration Analysis: Presentation to VGI Working Group
- Columbia University Vehicle Grid Integration in California: Cost-Benefit Comparison Study
- Sumitomo Comparison of VGI with DERs

"Stock-Takes" of Existing Efforts

Note: these were submitted by CPUC, CAISO, CEC, and Peninsula Clean Energy on behalf of CCAs, responding to a solicitation of "stock taking" of existing efforts

- CPUC
- CAISO
- CEC
- Community Choice Aggregators

ANNEX 2: PROCESS OF THE WORKING GROUP

The VGI Working Group operated over the course of more than ten months to develop the perspectives contained in this report and to produce the extensive materials on VGI use cases and policy recommendations that are available online (see Annex 1). Over 80 organizations participated in the Working Group. The Working Group had seven full-day or two-day workshops, many additional Working Group 2-hour calls, three working subgroups that each lasted several weeks and typically had weekly calls, and collaboration on this Final Report. Over ten separate solicitations were conducted of the entire Working Group for proposed use cases, screening and scoring of use cases, policy recommendations, a survey of opinions and comments on the policy recommendations, and several other types of inputs, all of which together which generated hundreds of recommendation items and tens of thousands of individual data points on the Working Group's assessments, opinions, and comments.

The Working Group had five basic stages:

Stage 1. Convening
Stage 2. Methodology development
Stage 3. Use case assessment: PUC Question (a)
Stage 4. Policy recommendations: PUC Question (b)
Stage 5. DER comparisons: PUC Question (c)

Stage 1

The VGI Working Group first convened on August 19, 2019 in Sacramento, with a day-long inter-agency workshop attended by about 45 participants in person and another 50 participants via conference call. The workshop began discussion of a proposed methodology for meeting Working Group objectives, reviewed foundational reference materials that would contribute to the work, and considered the connection of the Working Group with past and future policy initiatives.

Stage 2

Following that workshop, the VGI Working Group then began to conduct Stage 2, which continued through October 31, 2019. The purpose of Stage 2 was to develop and agree upon a framework and methodology for use case assessment. PG&E originally put forward a document "PG&E VGI Valuation Methodology." PG&E's methodology proposal was later amended to become a "Joint IOU" methodology proposal. The primary work of Stage 2 was by a "Subgroup A" composed of volunteers from the Working Group (see list below). This work by Subgroup A was followed by a full-day Working Group workshop on September 26 and a 2-hour Working Group call on October 3.

During the workshop, participants engaged in a brainstorming on the methodology and how to consider VGI use case value, benefits, and ranking. A report of this brainstorming captures a number of issues that were either taken up later in the Working Group or left for further use after the Working Group concludes. Following the workshop were a series of methodological discussions, including on the issue of issues requiring further resolution and further revisions to the methodology, which took place through October 31. The revisions to the methodology, and the considerations behind them, are documented in the Working Group's "Stage 2 Report," as well as a supplementary document "IOU Perspective on VGI Use-case Benefits and Costs."

Subgroup A Composition

Tom Ashley, Greenlots
Lance Atkins, Nissan
Noel Crisostomo, CEC
Jessie Denver, ECBE
Mauro Dresti, SCE
Karim Farhat, PG&E (*)
John Holmes, Paratelic Ventures
Peter Klauer, CAISO
Phillip Kobernick, PCE
Megha Lakhchaura, EVBox
Adam Langton, BMW
Taylor Marvin, SDG&E
Dave McCready, Ford
Pamela McDougal, NRDC
Marc Monbouquette, Enel X
Jin Noh, CESA
Stephanie Palmer, CARB
Richard Scholer, Fiat Chrysler
Jigar Shah, Electrify America
Carrie Sisto, CPUC
Anne Smart, ChargePoint
Jordan Smith, SCE
Dean Taylor, CalETC
Vincent Weyl, Kitu Systems
John Wheeler, Fermata Energy

(*) Karim Farhat participated in the VGI Working Group with three sequential affiliations, first on behalf of PG&E, then as an independent intervener, and then on behalf of ENGIE Impact. His participation in each Subgroup is noted with the appropriate affiliation.

Stage 3

Stage 3 began on September 30, 2020 to undertake the development, submission, screening, scoring, and ranking of use cases to answer PUC Question (a), "what use cases can provide value now, and how can that value be captured?" Stage 2 consisted of two in-person workshops, each 1-1/2 days long, on 11/14-11/15 and 1/22-1/23. Stage 2 concluded with a Working Group call on 1/30.

The bulk of the work of Stage 3 was led and conducted by a "Subgroup B" (see below for composition). The Subgroup formulated and issued a call-for-proposals for use case submissions invited from all participants. The call-for-proposals employed a fixed submission template agreed upon by the Subgroup. After intake, the Subgroup then organized ten "screening teams" of 3-4 people each to screen all submitted use cases. One of the ten teams was assigned the screening of all of the medium- and heavy-duty vehicle (MHV) use cases. All Working Group participants were also invited to provide parallel screening results of any use cases they wished, and additional screening results were submitted by a few individual participants, such that some use cases had multiple screening results.

The use cases to be screened were placed into a screening template and distributed randomly to the screening teams. Subgroup B then reviewed the screening and resolved a number of questioned use cases that screening teams had some uncertainty about how to screen.

Once the screening was completed, all the screened and "passed" use cases were provided to the full Working Group for scoring, in a set of scoring templates containing different sub-groups use cases organized by application or by sector. Individual participants were allowed to submit scoring results separately, or groups of participants working together could also submit jointly. Participants indicated in advance which subsets they planned to score, so that Subgroup B was able to anticipate what was going to be scored and if there would be any gaps in scoring. No participant was permitted to score a given use case more than once. The scoring results were compiled and summarized by Gridworks and provided back to the Working Group.

Participants who choose to do so then analyzed the compiled scoring results, and proposed methods and graphical means of grouping, ranking and displaying the scoring results. The compiled scoring results, the grouping methods and graphical displays, and proposed answers to the PUC Question (a) were all brought to the 1/22-1/23 workshop to discuss and achieve agreement and resolution. That process, and Stage 3, was then completed with a two-hour Working Group call on 1/30.

Subgroup B Composition

Hiba Abedrabo, Toyota
Meredith Alexander, CALSTART
Tom Ashley, Greenlots
Lance Atkins, NIssan
Alan Bach, Public Advocates Office
Anna Bella Korbatov, Fermata
Charlie Botsford, Honda
Dan Bowerson, Auto Alliance
Ed Burgess, Vehicle-Grid Integration Council
Noel Crisostomo, CEC
Eric Cutter, E3
Naor Deleanu, Olivine
Jessie Denver, EBCE
Mauro Dresti, SCE
Karim Farhat, PG&E
Wendy Fong, Lehigh University
Mehdi Ganji, Willdan Smart City Lead, and IEEE Smart City R&D Committee Chair
Jamie Hall, GM
John Holmes, Honda
Sam Houston, UCS
Christina Jeworski, Santa Clara VTA
Erick Karlan, Greenlots
Alex Keros, GM
Peter Klauer, CAISO
Phillip Kobernick, Peninsula Clean Energy
Fidel Leon Diaz, Public Advocates Office
Alexandra Leumer, ChargePoint
Taylor Marvin, SDG&E
Chris Michelbacher, Audi
Marc Monbouquette, Enel X
Miles Muller, NRDC
Stephanie Palmer, CARB
Max Parness, Toyota
Ed Pike, CPUC
Samantha Rosenbaum, Hubject
Jigar Shah, Electrify America
Carrie Sisto, CPUC
Jordan Smith, SCE
Hitesh Soneji, Olivine
Steve Tarnowsky, GM
Dean Taylor, CalETC
Vincent Weyl, Kitu Systems
John Wheeler, Fermata
Zach Woogen, Strategen
Eric Woychik, Willdan

Screening Teams

Team 1
Jordan Smith, SCE
Eric Woychik, Willdan
Erick Karlan, Greenlots
Jamie Hall, GM
Miles Muller, NRDC

Team 2
Dan Bowerson, Auto Alliance
Mehdi Ganji, Willdan Smart City
Tom Ashley, Greenlots
Vincent Weyl, Kitu Systems

Team 3
Eric Cutter, E3
John Wheeler, Fermata
Lance Atkins, NIssan
Fidel Leon Diaz, Public Advocates Office

Team 4
Anna Bella Korbatov,, Fermata
Noel Crisostomo CEC
Barton Sidles, Hubject
John Holmes, Honda

Team 5
Chris Michelbacher, Audi
Hitesh Soneji, Olivine
Taylor Marvin, SDG&E
Wendy Fong, LeHigh University

Team 6
Karim Farhat, PG&E
Naor Deleanu, Olivine
Steve Tarnowsky, GM
Samantha Rosenbaum, Hubject

Team 7
Alex Keros, GM
Alexandra Leumer, ChargePoint
Ed Burgess, Vehicle-Grid Integration Council
Jessie Denver EBCE

Team 8
Dean Taylor, CalETC
Jigar Shah, Electrify America
Hiba Abedrabo, Toyota
Zach Woogen, Vehicle-Grid Integration Council

Team 9 (MHDV Team)
Meredith Alexander, CALSTART
Samantha Houston, UCS
Christina Jaworski, Santa Clara VTA
Naor Deleanu, Olivine
Wendy Fong, Lehigh University
Jasna Tomic, CALSTART
Peter Klauer, CAISO

Team 10
Mauro Dresti, SCE
Marc Monbouquette, Enel

Stage 4

Stage 4 began on January 30, 2020 and concluded on May 15, 2020. During this stage, a "Subgroup C" was formed (composition below) and met weekly. The Subgroup first discussed and developed a policy recommendations framework and template. Then the template was used to solicit policy recommendations from the entire Working Group. The template contained early versions of the following fields: policy category, lead agency/entity, supporting agency/entity, timeframe, policy action, what does success look like, existing relevant policy forums and/or decisions, and notes. These fields were later expanded to include additional information (see Annex 6), and the original number of categories were expanded over three iterations from an initial six to nine, and then to eleven.

Approximately 120 policy recommendations were received from participants during a 2-3 week submission window. After this, the Subgroup undertook the following steps:

- Received CPUC Energy Division staff comments on the recommendations and asked submitters to respond to the comments; these responses were later added to the policy recommendations
- Identified potential duplications and overlaps of the recommendations and conducted a series of topical discussions and then bilateral and trilateral discussions to resolve, consolidate, and eliminate these duplications and overlaps
- Asked submitters to revise their recommendations based on discussions, including submitting new consolidation recommendations that superseded one or more prior recommendations
- Added comments from CAISO and CARB to the recommendations

- Developed 11 policy categories with which to number and group the recommendations to make reviewing and discussing more manageable
- Added “policy strategy tags” and “use case tags” to the recommendations
- Solicited additional supplementary documents and supporting information on the recommendations

During the execution of these steps, the full Working Group participated in a 1-1/2 day workshop on March 19-20 to review the recommendations and hold topical policy discussions. These discussions informed the further revisions and consolidations of the recommendations, and the presentation of these recommendations in Section B of this report.

Stage 4 Policy Survey

Once the recommendations were clarified and consolidated, Gridworks issued a policy survey to the Working Group consisting of four questions on each of the 109 policy recommendations that existed at that time. (The recommendations were later reduced to 92 recommendations as proponents withdrew or further consolidated the recommendations in coordination with other participants and proponents.

Q1. Do you agree or disagree that this recommendation will advance VGI in California?

5 - Strongly agree
4 – Agree
3 – Neutral
2 – Disagree
1 – Strongly disagree

Q2. How clear, understandable, and policy ready is this recommendation?

5 - Perfectly clear and policy ready
4 - Sufficiently clear and policy ready
3 - Needs some clarification
2 - Needs substantial clarification to be policy ready
1 - Needs to be re-written or re-thought

Q3. How critical and relevant is this policy to meeting your organization's own VGI objectives?

5 - Extremely critical and relevant
4 - Critical and relevant
3 - Not critical but still relevant
2 - Might be relevant
1 - Not relevant

Q4. Any other comments on this recommendation? Include any notes about how you see this recommendation connected to any of the other recommendations, including overlaps or complementarities.

Parties had two weeks to complete the survey. A total of 28 participants responded to the survey. Most recommendations had between 20-27 responses, as some participants did not respond to all 109 recommendations. The numerical results and comments from the policy survey are available in the Policy Recommendations Database, and also depicted graphically in Annex 9.

Subgroup C Composition

Hiba Abedrado (Toyota)
Lance Atkins (Nissan)
Alan Bach (Public Advocates Office)
Messay Betru (CEC)
Charlie Botsford (independent)
Dan Bowerson (Autos Innovate)
Ed Burgess (Vehicle-Grid Integration Council)
Albert Chiu (PG&E)
Naor Deleanu (Olivine)
Fidel Leon Diaz (Public Advocates Office)
Mauro Dresti (SCE)
Karim Farhat (independent)
Anja Gilbert (PG&E)
Jamie Hall (GM)
Yoshi Hirata (SEI Innovation)
David Holmberg (ESI TF)
John Holmes (Honda)
Christine Jaworsky (Santa Clara VTA)
Raymond Kaiser (Amzur)
Erick Karlen (Greenlots)
Alexander Keros (GM)
Peter Klauer (CAISO)
Corby Kristian (CalETC)
Alex Leumer (ChargePoint)
Taylor Marvin (SDG&E)
Jacob Mathew (Ford)
David Mintzer (Starboard Energy)
Adam Mohabbat (EVGo)
Marc Monbouquette (Enel)
Miles Muller (NRDC)
Amanda Myers (Energy Innovation)
Jin Noh (CESA)
Stephanie Palmer (CARB)
Jacqueline Piero (Nuvve)
Ed Pike (CPUC)
Maria Sanz-Moreno (PG&E)
Horie Satoko
Jigar Shah (Electrify America)
Carrie Sisto (CPUC)
Jordan Smith (SCE)
Hitesh Soneji (Olivine)
James Tarchinski (GM)
Dean Taylor (CalETC)
Matthew Tisdale (Gridworks)
Francesca Wahl (Tesla)
John Wheeler (Fermata)
Zach Woogan (Vehicle-Grid Integration Council)
Sarah Woogen (The Mobility House)

Stage 5

Stage 5 began on April 15, 2020 with a Working Group call to discuss ideas and options for responding to PUC Question (c) in the limited time available. A small "DER comparisons team" (composition below) was given the task of making recommendations to the Working Group in time for a Working Group call on April 30, 2020. After that call, further submissions from participants were solicited, and a final discussion on PUC Question (c) was held during a 1-1/2 day workshop on May 7-8, 2020.

The submissions and documents provided during these discussions are linked in Annex 1.

DER Comparisons Team Composition

Mauro Dresti (SCE)
Karim Farhat (ENGIE Impact)
Yoshi Hirata (Sumitomo)
Raymond Kaiser (Amzur)
Ed Pike (CPUC)
Maria Sanz-Moreno (PG&E)
Carrie Sisto (CPUC)
Zach Woogen (Vehicle-Grid Integration Council)
Sarah Woogen (The Mobility House)

ANNEX 3: RESOURCES AND REFERENCES

Note: these materials are provided for general reference but are not endorsed by the Working Group and were not reviewed in detail by the Working Group.

Foundational Materials

Vehicle-Grid Integration Roadmap. California Independent System Operator. February 2014. https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf

"Evaluating California's Vehicle-Grid Integration Opportunities: A Framing Document" Gridworks. August 2019. https://gridworks.org/wp-content/uploads/2019/08/Gridworks-VGI-Initiative-Framing-Document.pdf

CEC Interagency VGI Roadmap Update. https://www.energy.ca.gov/programs-and-topics/programs/california-vehicle-grid-integration-roadmap-update

PG&E's VGI Valuation Framework, as published in "A Comprehensive Guide to Electric Vehicle Managed Charging," SEPA. May 2019. https://sepapower.org/resource/a-comprehensive-guide-to-electric-vehicle-managed-charging/

E3, 2018, "Quantifying Value of V2G." https://epri.azureedge.net/documents/IWC/20181024/D1-9A_October%202018%20EPRI%20IWC_E3%20IWC%20V2G%20Slides.pdf

Distribution System Constrained Vehicle-to-Grid Services for Improved Grid Stability and Reliability https://www.researchgate.net/publication/331973231_Distribution_System_Constrained_Vehicle-to-_Grid_Services_for_Improved_Grid_Stability_and_Reliability

Value to the Grid from Managed Charging Based on California's High Renewables Study Link 3 8 "Electric Vehicle Grid Impacts and Value" Presentation by Bill Boyce (SMUD). June 2019. https://ieeexplore.ieee.org/document/8477179

EPIC 2.03b – Test Smart Inverter Enhanced Capabilities – Vehicle to Home; P 63-93 on Cost-Effectiveness. https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.03.pdf

CAISO Demand Response User Guide. http://www.caiso.com/Documents/DemandResponseUserGuide.pdf

CPUC Cost Effectiveness. https://www.cpuc.ca.gov/General.aspx?id=5267

DR Cost-Effectiveness Protocols. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11573

"2025 Demand Response Potential Study," LBNL. March 2017. https://drrc.lbl.gov/publications/2025-california-demand-response

"Phase Three Update Presentation" LBNL. July 2019. https://drrc.lbl.gov/news/article/slides-demand-response-potential

Local Sub-Area Energy Storage Request for Offers Solicitation Protocol – PAV and NMV metrics. https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2018 Local Sub-Area Energy Storage RFO/Local Sub Area RFO Protocol FINAL 022718.pdf

Avoided Cost of Transmission and Distribution Workshop Presentation. https://gridworks.org/wp-content/uploads/2019/08/Avoided-TD-Presentation-7.17.19_FINAL.pptx

CPUC/E3 Presentation on the value of Load Shift as determined in 2017 Integrated Resource Planning. Slides 5- 19. https://gridworks.org/wp-content/uploads/2018/04/04.18.18-Load-Shift-Working-Group-workshop-3_final.pdf

"Final Report of the California Public Utilities Commission's Load Shift Working Group," CPUC. January 2019. https://gridworks.org/wp-content/uploads/2019/02/LoadShiftWorkingGroup_report-1.pdf

Use Case Valuation

The Avoided Cost Calculator, CPUC. https://www.cpuc.ca.gov/general.aspx?id=5267

"Decision Adopting Cost Effective Analysis Framework Policies for all Distributed Energy Resources" http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M293/K833/293833387.PDF

"California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" CPUC. 2001. https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

State Agency Documents, Reports, and Web Pages

California Executive Order B-48-18. https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html

California Senate Bill 676. http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB676

California's Public Utilities Code Section 740.16. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB983

California SB 350 Transportation Electrification Programs. https://www.cpuc.ca.gov/sb350te/ , (D.18-05-040); https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457637

CALGreen (CCR, Title 24, Part 11). https://www.dgs.ca.gov/BSC/Resources/Page-Content/Building-Standards-Commission-Resources-List-Folder/CALGreen

CEC-CPUC-CAISO California Vehicle-Grid Integration Roadmap. https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf

CEC Vehicle-Grid Integration. https://ww2.energy.ca.gov/transportation/vehicle-grid-integration/

CEC VGI Roadmap. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-MISC-04

CEC Electric Program Investment Charge Program. https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program

CPUC Drive OIR (R.18-12-006) https://www.cpuc.ca.gov/vgi/

CPUC DRIVE OIR (R.18-12-006) Development of Rates and Infrastructure for Vehicle Electrification and Closing OIR; https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=252025566

CPUC VGI Working Group Scoping Ruling and Memo. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M285/K712/285712622.PDF

CPUC SGIP Program. https://www.cpuc.ca.gov/sgip/

CPUC Rule 21 Interconnection Proceeding (R.17-07-007). https://www.cpuc.ca.gov/Rule21/

CPUC Microgrids OIR (19-09-009). https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M314/K274/314274617.PDF

CPUC Zero Emission Vehicle Rate Programs. https://www.cpuc.ca.gov/General.aspx?id=12184

CPUC VGI Use Case Sub Group Final Report, 2018. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454524

Other References Provided by Working Group Participants

E3, Eric Cutter, 2019, "California Framework for Grid Value of Vehicle Grid Integration." https://gridworks.org/wp-content/uploads/2019/05/VGI_4.12-Slides.pdf

CalETC, 2020, "Infrastructure needs assessment for 5M light-duty vehicles in California by 2030" https://caletc.com/just-released-infrastructure-needs-assessment-for-5m-light-duty-vehicles-in-california-by-2030/

Electrify America comments on ESDER 4 comments. http://www.caiso.com/InitiativeDocuments/ElectrifyAmericaComments-EnergyStorage-DistributedEnergyResourcesPhase4-RevisedStrawProposal.pdf

Rocky Mountain Institute, 2019, "Reducing EV Charging Infrastructure Costs." https://rmi.org/insight/reducing-ev-charging-infrastructure-costs/

Cenex, "A Fresh Look at V2G Value Propositions." https://www.cenex.co.uk/app/uploads/2020/06/Fresh-Look-at-V2G-Value-Propositions.pdf

ANENX 4: USE CASE DEVELOPMENT, SUBMISSION, SCREENING, AND SCORING

Use Case Development and Submission

The Working Group was provided with an Excel use-case submission template. This template had a "use case database" on one tab, which provided the full set of 2,652 use cases possible from the options available for sector, application, type, approach, and resource alignment, along with unique use case ID numbers from 1 to 2652 (see Section A for description of these dimensions, and also the "Updated V2 IOU Joint Proposal on Use-Case Assessment Methodology" linked in Annex 1). All participants were invited to propose use cases from this master list of 2,652 use cases by entering use case numbers into the spreadsheet. The options in choosing and submitting use cases were:

Residential sector:

- Residential single-family home
- Residential multi-unit dwelling
- Residential single-family home charging by operator of a rideshare vehicle
- Residential multi-unit dwelling charging by operator of a rideshare vehicle

Commercial sector:

- Workplace charging (i.e., for employees)
- Public charging for "destination" trips (i.e., shopping centers)
- Public charging for commute trips (i.e., daytime public parking)
- Public destination charging by operator of a rideshare vehicle
- Public commute charging by operator of a rideshare vehicle

Commercial medium-duty and heavy-duty vehicles sector:

- Fleets of transit buses
- Fleets of school buses
- Fleets of small trucks
- Fleets of large trucks

Customer applications:

- Bill management – reduce energy bills or demand charges
- Upgrade deferral – defer costs of grid upgrades from interconnection of distributed generation
- Backup and resiliency – provide backup power for grid outages or other situations
- Renewable self-consumption – enable higher self-consumption of local distributed generation

System applications:

- Grid upgrade deferral – defer costs of grid upgrades
- Backup and resiliency – provide backup power for grid outages or other situations
- Voltage support – provide support for local distribution system voltage
- Day-ahead energy – sell to wholesale market
- Real-time energy – sell to wholesale market
- Renewable integration – help balance system peaks and ramps due to renewable generation
- GHG reduction – help balance system in ways that avoid GHG emissions

System resource adequacy applications (participate in resource adequacy markets):

System capacity
Flexible capacity
Local capacity

System ancillary services applications (participate in ancillary service markets):
Frequency regulation up/down
Spinning reserve
Non-spinning reserve

Approach:
Indirect
Direct

Type:
V1G
V2G

Resource alignment:
Unified and aligned
Fragmented and aligned
Fragmented and misaligned

The instructions provided with the use case submission template were:

- Review the full list of VGI use-cases in the use case database sheet
- Each use-case is provided a unique ID number (from 1 to 2652)
- To easily find a specific use case or group of use cases, you can use the sorting/filtering box for any column from the arrow in that column's heading
- To enter your list of VGI use-cases on your organization's sheet:
    - Fill in the ID column with the IDs of the use-cases you wish to select, one row per use case.
    - The rest of the columns will populate automatically
    - You can add as many use cases (rows) as you like
- If needed, fill in the optional Technology Characteristics columns
    - Please try to minimize multiple entries (rows) of the same use-case ID by consolidating or simplifying Technology Characteristics

Screening

A number of screening teams (see Annex 2) were provided with an Excel use case screening template with the following instructions. The template was pre-filled with a fixed number of randomly-assigned use cases for that team to screen. Each screening team went through one or more rounds of randomly-assigned use cases until all 1,060 submitted use cases were screened.

Procedure: subgroup leaders have provided your team with a subset of submitted use cases for your evaluation in the Screening tab. Go through every use case to assess whether it passes the screens or not. A list of all 7 screens is provided below. If a use-case passes all 7 screens, enter "x" in the "Pass" column. If a use-case does not pass one or more of the screens in the "now" Timeframe, enter "x" in all of the "Fail" columns for which it does not pass.

Timeframe for this screening: screen for "now" = 2019-2022

Technological feasibility:

> Screen 1: Filter out use-cases that require hardware and/or software technologies or solutions that, within the Timeframe: (1) have not been operated or demonstrated to operate in California, (2) are not compatible to California, and (3) are not easily adaptable to California. For clarification: technologies that are being piloted in California today are considered feasible and should not be filtered out within the “now” timeframe.

Market rules: from a market perspective, VGI use-cases can be broadly divided into three categories: (Category A) use-cases that can be implemented under existing market participation rules; (Category B) use-cases that are not possible to implement under existing market participation rules, but are possible to implement under updated rules in the specified Timeframe (e.g. within the “now” Timeframe, this includes market rules under consideration in active regulatory proceedings such as IDER and DDOR); (Category C) use-cases that are not possible to implement under existing market participation rules, and also not possible to implement under updated rules in the specified Timeframe (i.e. require substantial rule changes that will take longer than the duration of the specified Timeframe).

> Screen 2a: Filter out use-cases that fall into Category C involving applications and services that cannot be offered through existing or reformed/updated wholesale (e.g. CAISO) market participation rules within the Timeframe.
>
> Screen 2b: Filter out use-cases that fall into Category C involving applications or services that cannot be offered through existing or reformed/updated retail market participation rules (including utility rates and programs) within the Timeframe.

Customer preferences:

> Screen 3a: Filter out use-cases that significantly conflict with or compromise customer mobility needs or lifestyle preferences, within the Timeframe.
> Screen 3b: Filter out use-cases that are likely to have significantly low customer adoption rates and/or participation rates, within the Timeframe.

Data availability:

> Screen 4a: Filter out use-cases where data needed to quantify VGI value does not exist, and cannot be reasonably and reliably inferred or simulated, within the Timeframe. Necessary data is listed in detail in Steps 4a and 4b of the use-case assessment methodology; this could include, but is not limited to, the following: Reference unmanaged charging profiles, including total mobility energy need as well as charging behavior; Plug-in schedule that shows when the EV is connected and available to interact with the grid; Operational specifications of the offered service; Economic/monetary value of the offered service

Screen 4b: Filter out use-cases that can only be characterized and/or valuated using private data not publicly available within the Timeframe

Scoring

The scoring template used by the Working Group had these instructions:

Please score each use case in terms of benefits, costs, and "implementability" (re-termed "ease/risk of implementation" in the main report text for clarity). Please also add any optional comments related to economic benefit and cost scores, including references (reports, studies, analyses, etc.) to justify or explain your scoring, and also to explain your implementability score, and also to describe any non-economic benefit and/or cost.

Benefits:

- Benefits should focus only on the three "value creation" dimensions of the VGI Valuation Framework: Sector, Application, and Type.
- Benefits do not address how that benefit is captured via different forms and degrees of control mechanisms (Approach), or EV-EVSE resource fragmentation & alignment (Resource Alignment).
- For a specific combination of Sector, Application, and Type, Benefits refer to the "total addressable market", which accounts for two elements: Benefits per EV in the use case, and total available population of EVs in the use case.
- When assigning benefit scores, stakeholders should score the incremental benefits of VGI relative to a "reference" EV charging profile. This reference profile should focus on average market conditions related to unmanaged EV charging.
- Stakeholders are encouraged to think about the various factors that may influence these scores; a non-comprehensive list of those factors, for additional guidance:
    - Energy demand for mobility needs;
    - Schedule of when the EV is plugged-in and available to interact with the grid;
    - The magnitude of the economic signal (e.g. price of wholesale energy) to maximize or minimize charge/discharge over time;
    - V1G versus V2G;
    - Battery characteristics or constraints (e.g. battery capacity in kWh);
    - EV-EVSE characteristics or constraints (e.g. level of charging in kW)

- Benefits are scored using ranges of values for both per-vehicle benefits and total population of vehicles, i.e., $50-150/EV/year and 5,000-25,000 vehicles. Choose the best range from the available set of five possible drop-down ranges.
- Benefit value ranges are different for LDVs and MHVs.

Costs

- Costs should account for the following elements: hardware, software/IT, operation and management services, administrative expenses.
- Please provide an overall cost score, and in addition, an optional set of individual scores for hardware, software/IT, operational and management services, and administrative expenses.

- Cost should be assessed within a specific Timeframe (i.e. 2019 - 2022 for evaluation within the “now” timeframe).
- Cost in this Methodology shall be either the participating Customer (for Customer - Application use - cases) or California overall (for System - Application use - cases).
- For a specific combination of Sector, Application, Type, Approach, and Resource Alignment, costs refer to “expenses incurred by the buyer ”. The "cost to the buyer" is the same as the price charged by the seller.
- This methodology does not require identifying private or internal costs borne by service or equipment providers for providing services or producing components.
- All cost scores are a choice of values 1 through 5, with 1=very low, 2=low, 3=moderate, 4=high, and 5=very high.

Implementability

- Implementability is defined as “difficulty and risk associated with implementing and scaling up” a use case.
- Implementability accounts for four interrelated elements, which may be interpreted subjectively by different stakeholders: (a) difficulty of implementation, (b) difficulty of scaling up, (c) risk of implementation, and (d) risk of scaling up.
- Implementability is scored with a choice of values 1 through 5, with 1 = very difficult and risky to implement/scale-up, 2- = difficult or risky to implement/scale-up, 3 = neutral to implement/scale-up, 4 = easy or not risky to implement/scale-up, and 5 = very easy and not risky to implement/scale-up
- In addition to the Implementability Score, stakeholders can provide text comments to qualitatively document the most prominent considerations that influenced their score. A wide range of considerations might influence the Implementability Score. Stakeholders are encouraged to explain the most influential considerations with any or all of the four interrelated elements.

Non-economic benefits (optional)

- Characterize briefly any non-economic benefits that you think are important in understanding or assessing the value of this use case. These could include, for example, GHG reduction, air quality improvement, better renewable integration, etc.

Cost, Benefit, and Implementability Scoring Ranges Adopted

The scoring template had these pre-defined options for relative scoring of benefits, costs, and implementability on scales of 1-5:

LDV benefit per vehicle ($/EV/year)
1 = 1-50
2 = 50-150
3 = 150-300
4 = 300-600
5 = 600-1000

LDV “population that could (will be able to) participate by 2022”
1 = 1 - 5,000
2 = 5,000 - 25,000
3 = 25,000 - 100,000
4 = 100,000 - 300,000
5 = 300,000 - 900,000

Costs (Overall, Hardware, Software, Operation & Management, Administration)
1 = very low
2 = low
3 = moderate
4 = high
5 = very high

MHDV benefit per vehicle ($/EV/year)
1 = 1-500
2 = 500-1,500
3 = 1,500-3,000
4 = 3,000-6,000
5 = 6,000-10,000

MHDV “population that could (will be able to) participate by 2022”
1 = 1 - 200
2 = 200-600
3 = 600-1,200
4 = 1,200-2,500
5 = 2,500-5,000

Implementability (later called ease/risk of implementation in the Final Report)
1 = very difficult and risky to implement/scale-up
2 = difficult or risky to implement/scale-up
3 = neutral to implement/scale-up
4 = easy or not risky to implement/scale-up
5 = very easy and not risky to implement/scale-up

MHDV Use Case Scoring and Vehicle Types

A team of Working Group participants that had been focusing on scoring MHDV use cases produced a white paper on MHDV use cases, “Development of Market Analysis and Use-Cases for Medium & Heavy-Duty Vehicle-Grid Integration” (see Annex 1 for link), and also developed a set of vehicle types for each MHDV sector. Scoring of the MHDV use cases, in contrast to the LDV use cases, allowed for a drop-down menu of vehicle type when scoring. Different vehicle types were then designated with sub-numbering 1873.1, 1873.2, etc. and scoring was tabulated separately for each sub-number. The MHDV vehicle types used for scoring are given in the following table:

	Battery Capacity (kwh)	Charger Power (kw)	Other Technology Notes
Small Truck A	70-100 kWh	10-19 kW	Small Truck A: Class 5 Last Mile Delivery with L2 charging; Daytime deliveries, full charge satisfies duty cycle; needs 100% SOC to start shift between 1 and 6 AM.
Small Truck B	70-100 kWh	25 kW	Small Truck B: Class 5 Last Mile Delivery with low power DCFC; Daytime deliveries, full charge satisfies duty cycle; needs 100% SOC to start shift between 1 and 6 AM.
Long Range Transit Bus A	440 kWh	125 kW	Long Range Bus/Average Mile Route - depot overnight charging; duty cycle 06:00-20:00; 170 miles/day
Long Range Transit Bus B	440 kWh	125 kW	Long Range Bus/Average Mile Route - Enroute charging; duty cycle 06:00-20:00; 170 miles/day
Long Range Transit Bus C	440 kWh	125 kW	Long Range Bus/High Mileage Route - Depot and Enroute charging; duty cycle 04:00 to 01:00 next day; 230 miles/day
Short Range Transit Bus A	330 kWh	125 kW	Short Range Bus/Commuter Route - Overnight Depot Charging; Duty cycle 06:00-09:00 AND 14:00-18:00
Short Range Transit Bus B	330 kWh	125 kW	Short Range Bus/Commuter Route - Afternoon and Overnight Depot Charging; Duty cycle 06:00-09:00 AND 14:00-18:00
Airport Shuttle Bus		50 kW	Airport Shuttle Bus: frequent short trips, in use 5 AM-midnight; overnight charge, may be able to charge at midday
Transit Shuttle Van		L2	less frequent trips to serve transit need; overnight charging
Large Truck A	200-300 kWh	30-50 kW DC	Class 6 Short Haul Delivery - overnight charging, opportunistic daytime charging; duty cycle 03:00 start, return to depot b/w 14:00-19:00
Large Truck B	300 kWh	100 kW DC	Class 8 drayage/delivery - overnight charging only; duty cycle 03:00 start, return to depot b/w 14:00-19:00
Large Truck C	450 kWh	150 kW DC	Class 8 Drayage/Delivery - overnight charging, opportunistic daytime charging; duty cycle 03:00 start, return to depot b/w 14:00-19:00
School Bus A	156 kWh	18 kW L2 or 60 kW with V2G	School Bus Type D (36,200 lbs. GVWR): duty cycle 07:00-0:900 and 014:00-16:00
School Bus B	106-127 kWh	25 kW 3-phase L2	School Bus Type C (22,000 lbs. GVWR): duty cycle 07:00-0:900 and 014:00-16:00
School Bus C	85-127 kWh	25 kW 3-phase L2	School Bus Type B (14,000 lbs. GVWR): duty cycle 07:00-0:900 and 014:00-16:00

ANNEX 5: VGI USE CASES ABLE TO PROVIDE VALUE NOW

The following table gives all 320 use cases that were scored during the use case assessment stage of the Working Group and that were deemed, for the purposes of answering PUC Question (a), as "able to provide value now." See Section A for further details. The scorings received plus further details of the use cases, are provided in the Use Case Assessment Database.

Notes: Commercial fleet small truck is class 2-5 and large truck is class 6-8. Residential SFH stands for single-family home and Residential MUD stands for multi-unit dwelling. Uses cases with the same number but different decimals (i.e., 13.1, 13.2, 1877.1, 1877.2) are different technology variants of the same use case. For details on these technology variants refer to the Use Case Assessment Database.

ID	Sector	Application	Approach	Type	Resource Alignment
1.1	Residential – SFH	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1.2	Residential – SFH	Customer – Bill Management	Indirect	V1G	Unified, Aligned
4	Residential – SFH	Customer – Bill Management	Direct	V1G	Unified, Aligned
7	Residential – SFH	Customer – Bill Management	Indirect	V2G	Unified, Aligned
10	Residential – SFH	Customer – Bill Management	Direct	V2G	Unified, Aligned
13.1	Residential – SFH	Customer – Upgrade Deferral	Indirect	V1G	Unified, Aligned
13.2	Residential – SFH	Customer – Upgrade Deferral	Indirect	V1G	Unified, Aligned
16	Residential – SFH	Customer – Upgrade Deferral	Direct	V1G	Unified, Aligned
19	Residential – SFH	Customer – Upgrade Deferral	Indirect	V2G	Unified, Aligned
31	Residential – SFH	Customer – Backup, Resiliency	Indirect	V2G	Unified, Aligned
34	Residential – SFH	Customer – Backup, Resiliency	Direct	V2G	Unified, Aligned
37	Residential – SFH	Customer -Renewable Self-Consumption	Indirect	V1G	Unified, Aligned
40	Residential – SFH	Customer -Renewable Self-Consumption	Direct	V1G	Unified, Aligned
46	Residential – SFH	Customer -Renewable Self-Consumption	Direct	V2G	Unified, Aligned
49	Residential – SFH	System – Grid Upgrade Deferral	Indirect	V1G	Unified, Aligned
52	Residential – SFH	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
67	Residential – SFH	System – Backup, Resiliency	Indirect	V2G	Unified, Aligned
70	Residential – SFH	System – Backup, Resiliency	Direct	V2G	Unified, Aligned
82	Residential – SFH	System – Voltage Support	Direct	V2G	Unified, Aligned
85	Residential – SFH	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
88	Residential – SFH	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
100	Residential – SFH	System – Real-Time Energy	Direct	V1G	Unified, Aligned
109	Residential – SFH	System – Renewable Integration	Indirect	V1G	Unified, Aligned
112	Residential – SFH	System – Renewable Integration	Direct	V1G	Unified, Aligned
115	Residential – SFH	System – Renewable Integration	Indirect	V2G	Unified, Aligned
118	Residential – SFH	System – Renewable Integration	Direct	V2G	Unified, Aligned
121	Residential – SFH	System – GHG Reduction	Indirect	V1G	Unified, Aligned
124	Residential – SFH	System – GHG Reduction	Direct	V1G	Unified, Aligned
130	Residential – SFH	System – GHG Reduction	Direct	V2G	Unified, Aligned
133	Residential – SFH	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
136	Residential – SFH	System – RA, System Capacity	Direct	V1G	Unified, Aligned
142	Residential – SFH	System – RA, System Capacity	Direct	V2G	Unified, Aligned
148	Residential – SFH	System – RA, Flex Capacity	Direct	V1G	Unified, Aligned
160	Residential – SFH	System – RA, Local Capacity	Direct	V1G	Unified, Aligned
205	Residential – SFH – Rideshare	Customer – Bill Management	Indirect	V1G	Unified, Aligned
208	Residential – SFH – Rideshare	Customer – Bill Management	Direct	V1G	Unified, Aligned
241	Residential – SFH – Rideshare	Customer – RE Self-Consumption	Indirect	V1G	Unified, Aligned
253	Residential – SFH – Rideshare	System – Grid Upgrade Deferral	Indirect	V1G	Unified, Aligned
256	Residential – SFH – Rideshare	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
292	Residential – SFH – Rideshare	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
313	Residential – SFH – Rideshare	System – Renewable Integration	Indirect	V1G	Unified, Aligned
316	Residential – SFH – Rideshare	System – Renewable Integration	Direct	V1G	Unified, Aligned
328	Residential – SFH – Rideshare	System – GHG Reduction	Direct	V1G	Unified, Aligned
337	Residential – SFH – Rideshare	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
340	Residential – SFH – Rideshare	System – RA, System Capacity	Direct	V1G	Unified, Aligned
410	Residential – MUD	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
413.1	Residential – MUD	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
413.2	Residential – MUD	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
414	Residential – MUD	Customer – Bill Management	Direct	V1G	Fragmented, Misaligned
416	Residential – MUD	Customer – Bill Management	Indirect	V2G	Fragmented, Aligned

419	Residential – MUD	Customer – Bill Management	Direct	V2G	Fragmented, Aligned
422	Residential – MUD	Customer – Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
425	Residential – MUD	Customer – Upgrade Deferral	Direct	V1G	Fragmented, Aligned
426	Residential – MUD	Customer – Upgrade Deferral	Direct	V1G	Fragmented, Misaligned
431	Residential – MUD	Customer – Upgrade Deferral	Direct	V2G	Fragmented, Aligned
440	Residential – MUD	Customer – Backup, Resiliency	Indirect	V2G	Fragmented, Aligned
443	Residential – MUD	Customer – Backup, Resiliency	Direct	V2G	Fragmented, Aligned
446	Residential – MUD	Customer- Renewable Self-Consumption	Indirect	V1G	Fragmented, Aligned
449	Residential – MUD	Customer- Renewable Self-Consumption	Direct	V1G	Fragmented, Aligned
455	Residential – MUD	Customer-Renewable Self-Consumption	Direct	V2G	Fragmented, Aligned
458	Residential – MUD	System – Grid Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
461	Residential – MUD	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Aligned
476	Residential – MUD	System – Backup, Resiliency	Indirect	V2G	Fragmented, Aligned
479	Residential – MUD	System – Backup, Resiliency	Direct	V2G	Fragmented, Aligned
497	Residential – MUD	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
498	Residential – MUD	System – Day-Ahead Energy	Direct	V1G	Fragmented, Misaligned
509	Residential – MUD	System – Real-Time Energy	Direct	V1G	Fragmented, Aligned
518	Residential – MUD	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
521	Residential – MUD	System – Renewable Integration	Direct	V1G	Fragmented, Aligned
527	Residential – MUD	System – Renewable Integration	Direct	V2G	Fragmented, Aligned
533	Residential – MUD	System – GHG Reduction	Direct	V1G	Fragmented, Aligned
539	Residential – MUD	System – GHG Reduction	Direct	V2G	Fragmented, Aligned
542	Residential – MUD	System – RA, System Capacity	Indirect	V1G	Fragmented, Aligned
545	Residential – MUD	System – RA, System Capacity	Direct	V1G	Fragmented, Aligned
569	Residential – MUD	System – RA, Local Capacity	Direct	V1G	Fragmented, Aligned
575	Residential – MUD	System – RA, Local Capacity	Direct	V2G	Fragmented, Aligned
581	Residential – MUD	System-Frequency Regulation Up/Down	Direct	V1G	Fragmented, Aligned
614	Residential – MUD – Rideshare	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
617	Residential – MUD – Rideshare	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
626	Residential – MUD – Rideshare	Customer – Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
650	Residential – MUD – Rideshare	Customer -Renewable Self-Consumption	Indirect	V1G	Fragmented, Aligned
698	Residential – MUD – Rideshare	System – Day-Ahead Energy	Indirect	V1G	Fragmented, Aligned
701	Residential – MUD – Rideshare	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
725	Residential – MUD – Rideshare	System – Renewable Integration	Direct	V1G	Fragmented, Aligned
734	Residential – MUD – Rideshare	System – GHG Reduction	Indirect	V1G	Fragmented, Aligned
737	Residential – MUD – Rideshare	System – GHG Reduction	Direct	V1G	Fragmented, Aligned
746	Residential – MUD – Rideshare	System – RA, System Capacity	Indirect	V1G	Fragmented, Aligned
749	Residential – MUD – Rideshare	System – RA, System Capacity	Direct	V1G	Fragmented, Aligned
817	Commercial – Workplace	Customer – Bill Management	Indirect	V1G	Unified, Aligned
818	Commercial – Workplace	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
820	Commercial – Workplace	Customer – Bill Management	Direct	V1G	Unified, Aligned
821	Commercial – Workplace	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
822	Commercial – Workplace	Customer – Bill Management	Direct	V1G	Fragmented, Misaligned
826	Commercial – Workplace	Customer – Bill Management	Direct	V2G	Unified, Aligned
826.1	Commercial – Workplace	Customer – Bill Management	Direct	V2G	Unified, Aligned
826.2	Commercial – Workplace	Customer – Bill Management	Direct	V2G	Unified, Aligned
827	Commercial – Workplace	Customer – Bill Management	Direct	V2G	Fragmented, Aligned
827.1	Commercial – Workplace	Customer – Bill Management	Direct	V2G	Fragmented, Aligned
827.2	Commercial – Workplace	Customer – Bill Management	Direct	V2G	Fragmented, Aligned
828	Commercial – Workplace	Customer – Bill Management	Direct	V2G	Fragmented, Misaligned
830	Commercial – Workplace	Customer – Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
833	Commercial – Workplace	Customer – Upgrade Deferral	Direct	V1G	Fragmented, Aligned
834	Commercial – Workplace	Customer – Upgrade Deferral	Direct	V1G	Fragmented, Misaligned
839	Commercial – Workplace	Customer – Upgrade Deferral	Direct	V2G	Fragmented, Aligned
848	Commercial – Workplace	Customer – Backup, Resiliency	Indirect	V2G	Fragmented, Aligned
850	Commercial – Workplace	Customer – Backup, Resiliency	Direct	V2G	Unified, Aligned
850.1	Commercial – Workplace	Customer – Backup, Resiliency	Direct	V2G	Unified, Aligned
850.2	Commercial – Workplace	Customer – Backup, Resiliency	Direct	V2G	Unified, Aligned
851	Commercial – Workplace	Customer – Backup, Resiliency	Direct	V2G	Fragmented, Aligned
853	Commercial – Workplace	Customer -Renewable Self-Consumption	Indirect	V1G	Unified, Aligned
854	Commercial – Workplace	Customer -Renewable Self-Consumption	Indirect	V1G	Fragmented, Aligned
856	Commercial – Workplace	Customer -Renewable Self-Consumption	Direct	V1G	Unified, Aligned
857	Commercial – Workplace	Customer -Renewable Self-Consumption	Direct	V1G	Fragmented, Aligned
860	Commercial – Workplace	Customer -Renewable Self-Consumption	Indirect	V2G	Fragmented, Aligned
862	Commercial – Workplace	Customer -Renewable Self-Consumption	Direct	V2G	Unified, Aligned
863	Commercial – Workplace	Customer -Renewable Self-Consumption	Direct	V2G	Fragmented, Aligned
866	Commercial – Workplace	System – Grid Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
869	Commercial – Workplace	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Aligned
870	Commercial – Workplace	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Misaligned

872	Commercial – Workplace	System – Grid Upgrade Deferral	Indirect	V2G	Fragmented, Aligned
874	Commercial – Workplace	System – Grid Upgrade Deferral	Direct	V2G	Unified, Aligned
875	Commercial – Workplace	System – Grid Upgrade Deferral	Direct	V2G	Fragmented, Aligned
884	Commercial – Workplace	System – Backup, Resiliency	Indirect	V2G	Fragmented, Aligned
886	Commercial – Workplace	System – Backup, Resiliency	Direct	V2G	Unified, Aligned
887	Commercial – Workplace	System – Backup, Resiliency	Direct	V2G	Fragmented, Aligned
899	Commercial – Workplace	System – Voltage Support	Direct	V2G	Fragmented, Aligned
901	Commercial – Workplace	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
902	Commercial – Workplace	System – Day-Ahead Energy	Indirect	V1G	Fragmented, Aligned
904	Commercial – Workplace	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
905	Commercial – Workplace	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
906	Commercial – Workplace	System – Day-Ahead Energy	Direct	V1G	Fragmented, Misaligned
908	Commercial – Workplace	System – Day-Ahead Energy	Indirect	V2G	Fragmented, Aligned
917	Commercial – Workplace	System – Real-Time Energy	Direct	V1G	Fragmented, Aligned
918	Commercial – Workplace	System – Real-Time Energy	Direct	V1G	Fragmented, Misaligned
925	Commercial – Workplace	System – Renewable Integration	Indirect	V1G	Unified, Aligned
926	Commercial – Workplace	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
928	Commercial – Workplace	System – Renewable Integration	Direct	V1G	Unified, Aligned
929	Commercial – Workplace	System – Renewable Integration	Direct	V1G	Fragmented, Aligned
930	Commercial – Workplace	System – Renewable Integration	Direct	V1G	Fragmented, Misaligned
932	Commercial – Workplace	System – Renewable Integration	Indirect	V2G	Fragmented, Aligned
934	Commercial – Workplace	System – Renewable Integration	Direct	V2G	Unified, Aligned
935	Commercial – Workplace	System – Renewable Integration	Direct	V2G	Fragmented, Aligned
937	Commercial – Workplace	System – GHG Reduction	Indirect	V1G	Unified, Aligned
938	Commercial – Workplace	System – GHG Reduction	Indirect	V1G	Fragmented, Aligned
940	Commercial – Workplace	System – GHG Reduction	Direct	V1G	Unified, Aligned
941	Commercial – Workplace	System – GHG Reduction	Direct	V1G	Fragmented, Aligned
942	Commercial – Workplace	System – GHG Reduction	Direct	V1G	Fragmented, Misaligned
946	Commercial – Workplace	System – GHG Reduction	Direct	V2G	Unified, Aligned
947	Commercial – Workplace	System – GHG Reduction	Direct	V2G	Fragmented, Aligned
949	Commercial – Workplace	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
950	Commercial – Workplace	System – RA, System Capacity	Indirect	V1G	Fragmented, Aligned
952	Commercial – Workplace	System – RA, System Capacity	Direct	V1G	Unified, Aligned
953	Commercial – Workplace	System – RA, System Capacity	Direct	V1G	Fragmented, Aligned
958	Commercial – Workplace	System – RA, System Capacity	Direct	V2G	Unified, Aligned
959	Commercial – Workplace	System – RA, System Capacity	Direct	V2G	Fragmented, Aligned
964	Commercial – Workplace	System – RA, Flex Capacity	Direct	V1G	Unified, Aligned
970	Commercial – Workplace	System – RA, Flex Capacity	Direct	V2G	Unified, Aligned
971	Commercial – Workplace	System – RA, Flex Capacity	Direct	V2G	Fragmented, Aligned
972	Commercial – Workplace	System – RA, Flex Capacity	Direct	V2G	Fragmented, Misaligned
976	Commercial – Workplace	System – RA, Local Capacity	Direct	V1G	Unified, Aligned
977	Commercial – Workplace	System – RA, Local Capacity	Direct	V1G	Fragmented, Aligned
989	Commercial – Workplace	System-Frequency Regulation Up/Down	Direct	V1G	Fragmented, Aligned
994	Commercial – Workplace	System-Frequency Regulation Up/Down	Direct	V2G	Unified, Aligned
995	Commercial – Workplace	System-Frequency Regulation Up/Down	Direct	V2G	Fragmented, Aligned
1022	Commercial – Public, Destination	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
1024	Commercial – Public, Destination	Customer – Bill Management	Direct	V1G	Unified, Aligned
1025	Commercial – Public, Destination	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
1026	Commercial – Public, Destination	Customer – Bill Management	Direct	V1G	Fragmented, Misaligned
1028	Commercial – Public, Destination	Customer – Bill Management	Indirect	V2G	Fragmented, Aligned
1034	Commercial – Public, Destination	Customer – Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
1037	Commercial – Public, Destination	Customer – Upgrade Deferral	Direct	V1G	Fragmented, Aligned
1038	Commercial – Public, Destination	Customer – Upgrade Deferral	Direct	V1G	Fragmented, Misaligned
1074	Commercial – Public, Destination	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Misaligned
1088	Commercial – Public, Destination	System – Backup, Resiliency	Indirect	V2G	Fragmented, Aligned
1097	Commercial – Public, Destination	System – Voltage Support	Direct	V1G	Fragmented, Aligned
1098	Commercial – Public, Destination	System – Voltage Support	Direct	V1G	Fragmented, Misaligned
1109	Commercial – Public, Destination	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
1110	Commercial – Public, Destination	System – Day-Ahead Energy	Direct	V1G	Fragmented, Misaligned
1121	Commercial – Public, Destination	System – Real-Time Energy	Direct	V1G	Fragmented, Aligned
1130	Commercial – Public, Destination	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
1133	Commercial – Public, Destination	System – Renewable Integration	Direct	V1G	Fragmented, Aligned
1134	Commercial – Public, Destination	System – Renewable Integration	Direct	V1G	Fragmented, Misaligned
1142	Commercial – Public, Destination	System – GHG Reduction	Indirect	V1G	Fragmented, Aligned
1145	Commercial – Public, Destination	System – GHG Reduction	Direct	V1G	Fragmented, Aligned
1153	Commercial – Public, Destination	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
1154	Commercial – Public, Destination	System – RA, System Capacity	Indirect	V1G	Fragmented, Aligned
1157	Commercial – Public, Destination	System – RA, System Capacity	Direct	V1G	Fragmented, Aligned
1158	Commercial – Public, Destination	System – RA, System Capacity	Direct	V1G	Fragmented, Misaligned

1226	Commercial – Public, Dest/Rideshare	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
1228	Commercial – Public, Dest/Rideshare	Customer – Bill Management	Direct	V1G	Unified, Aligned
1230	Commercial – Public, Dest/Rideshare	Customer – Bill Management	Direct	V1G	Fragmented, Misaligned
1277	Commercial – Public, Dest/Rideshare	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Aligned
1310	Commercial – Public, Dest/Rideshare	System – Day-Ahead Energy	Indirect	V1G	Fragmented, Aligned
1313	Commercial – Public, Dest/Rideshare	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
1314	Commercial – Public, Dest/Rideshare	System – Day-Ahead Energy	Direct	V1G	Fragmented, Misaligned
1316	Commercial – Public, Dest/Rideshare	System – Day-Ahead Energy	Indirect	V2G	Fragmented, Aligned
1334	Commercial – Public, Dest/Rideshare	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
1337	Commercial – Public, Dest/Rideshare	System – Renewable Integration	Direct	V1G	Fragmented, Aligned
1338	Commercial – Public, Dest/Rideshare	System – Renewable Integration	Direct	V1G	Fragmented, Misaligned
1349	Commercial – Public, Dest/Rideshare	System – GHG Reduction	Direct	V1G	Fragmented, Aligned
1361	Commercial – Public, Dest/Rideshare	System – RA, System Capacity	Direct	V1G	Fragmented, Aligned
1362	Commercial – Public, Dest/Rideshare	System – RA, System Capacity	Direct	V1G	Fragmented, Misaligned
1430	Commercial – Public, Commute	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
1434	Commercial – Public, Commute	Customer – Bill Management	Direct	V1G	Fragmented, Misaligned
1436	Commercial – Public, Commute	Customer – Bill Management	Indirect	V2G	Fragmented, Aligned
1442	Commercial – Public, Commute	Customer – Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
1466	Commercial – Public, Commute	Customer -Renewable Self-Consumption	Indirect	V1G	Fragmented, Aligned
1478	Commercial – Public, Commute	System – Grid Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
1481	Commercial – Public, Commute	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Aligned
1514	Commercial – Public, Commute	System – Day-Ahead Energy	Indirect	V1G	Fragmented, Aligned
1517	Commercial – Public, Commute	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
1518	Commercial – Public, Commute	System – Day-Ahead Energy	Direct	V1G	Fragmented, Misaligned
1538	Commercial – Public, Commute	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
1541	Commercial – Public, Commute	System – Renewable Integration	Direct	V1G	Fragmented, Aligned
1542	Commercial – Public, Commute	System – Renewable Integration	Direct	V1G	Fragmented, Misaligned
1544	Commercial – Public, Commute	System – Renewable Integration	Indirect	V2G	Fragmented, Aligned
1565	Commercial – Public, Commute	System – RA, System Capacity	Direct	V1G	Fragmented, Aligned
1578	Commercial – Public, Commute	System – RA, Flex Capacity	Direct	V1G	Fragmented, Misaligned
1633	Comm.-Public, Commute/Rideshare	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1634	Comm.-Public, Commute/Rideshare	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
1636	Comm.-Public, Commute/Rideshare	Customer – Bill Management	Direct	V1G	Unified, Aligned
1637	Comm.-Public, Commute/Rideshare	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
1640	Comm.-Public, Commute/Rideshare	Customer – Bill Management	Indirect	V2G	Fragmented, Aligned
1648	Comm.-Public, Commute/Rideshare	Customer – Upgrade Deferral	Direct	V1G	Unified, Aligned
1682	Comm.-Public, Commute/Rideshare	System – Grid Upgrade Deferral	Indirect	V1G	Fragmented, Aligned
1685	Comm.-Public, Commute/Rideshare	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Aligned
1686	Comm.-Public, Commute/Rideshare	System – Grid Upgrade Deferral	Direct	V1G	Fragmented, Misaligned
1700	Comm.-Public, Commute/Rideshare	System – Backup, Resiliency	Indirect	V2G	Fragmented, Aligned
1718	Comm.-Public, Commute/Rideshare	System – Day-Ahead Energy	Indirect	V1G	Fragmented, Aligned
1721	Comm.-Public, Commute/Rideshare	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
1722	Comm.-Public, Commute/Rideshare	System – Day-Ahead Energy	Direct	V1G	Fragmented, Misaligned
1733	Comm.-Public, Commute/Rideshare	System – Real-Time Energy	Direct	V1G	Fragmented, Aligned
1741	Comm.-Public, Commute/Rideshare	System – Renewable Integration	Indirect	V1G	Unified, Aligned
1742	Comm.-Public, Commute/Rideshare	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
1744	Comm.-Public, Commute/Rideshare	System – Renewable Integration	Direct	V1G	Unified, Aligned
1745	Comm.-Public, Commute/Rideshare	System – Renewable Integration	Direct	V1G	Fragmented, Aligned
1746	Comm.-Public, Commute/Rideshare	System – Renewable Integration	Direct	V1G	Fragmented, Misaligned
1748	Comm.-Public, Commute/Rideshare	System – Renewable Integration	Indirect	V2G	Fragmented, Aligned
1753	Comm.-Public, Commute/Rideshare	System – GHG Reduction	Indirect	V1G	Unified, Aligned
1756	Comm.-Public, Commute/Rideshare	System – GHG Reduction	Direct	V1G	Unified, Aligned
1757	Comm.-Public, Commute/Rideshare	System – GHG Reduction	Direct	V1G	Fragmented, Aligned
1766	Comm.-Public, Commute/Rideshare	System – RA, System Capacity	Indirect	V1G	Fragmented, Aligned
1769	Comm.-Public, Commute/Rideshare	System – RA, System Capacity	Direct	V1G	Fragmented, Aligned
1793	Comm.-Public, Commute/Rideshare	System – RA, Local Capacity	Direct	V1G	Fragmented, Aligned
1837.1	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1837.2	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1837.3	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1837.4	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1837.5	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1837.6	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Unified, Aligned
1838.1	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
1838.2	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
1840.1	Commercial – Fleet, Transit Bus	Customer – Bill Management	Direct	V1G	Unified, Aligned
1840.2	Commercial – Fleet, Transit Bus	Customer – Bill Management	Direct	V1G	Unified, Aligned
1841.1	Commercial – Fleet, Transit Bus	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
1841.2	Commercial – Fleet, Transit Bus	Customer – Bill Management	Direct	V1G	Fragmented, Aligned
1843	Commercial – Fleet, Transit Bus	Customer – Bill Management	Indirect	V2G	Unified, Aligned

1846	Commercial – Fleet, Transit Bus	Customer – Bill Management	Direct	V2G	Unified, Aligned
1873.1	Commercial – Fleet, Transit Bus	Customer -Renewable Self-Consumption	Indirect	V1G	Unified, Aligned
1873.2	Commercial – Fleet, Transit Bus	Customer -Renewable Self-Consumption	Indirect	V1G	Unified, Aligned
1876.1	Commercial – Fleet, Transit Bus	Customer -Renewable Self-Consumption	Direct	V1G	Unified, Aligned
1876.2	Commercial – Fleet, Transit Bus	Customer -Renewable Self-Consumption	Direct	V1G	Unified, Aligned
1877.1	Commercial – Fleet, Transit Bus	Customer -Renewable Self-Consumption	Direct	V1G	Unified, Aligned
1877.2	Commercial – Fleet, Transit Bus	Customer -Renewable Self-Consumption	Direct	V1G	Unified, Aligned
1886.1	Commercial – Fleet, Transit Bus	System – Grid Upgrade Deferral	Indirect	V1G	Unified, Aligned
1888.1	Commercial – Fleet, Transit Bus	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
1888.2	Commercial – Fleet, Transit Bus	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
1921.1	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
1921.2	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
1921.3	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
1924.1	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
1924.2	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
1924.3	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
1925.1	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
1925.2	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
1925.3	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
1925.4	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V1G	Fragmented, Aligned
1930.1	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V2G	Unified, Aligned
1930.2	Commercial – Fleet, Transit Bus	System – Day-Ahead Energy	Direct	V2G	Unified, Aligned
1936.1	Commercial – Fleet, Transit Bus	System – Real-Time Energy	Direct	V1G	Unified, Aligned
1936.2	Commercial – Fleet, Transit Bus	System – Real-Time Energy	Direct	V1G	Unified, Aligned
1936.3	Commercial – Fleet, Transit Bus	System – Real-Time Energy	Direct	V1G	Unified, Aligned
1936.4	Commercial – Fleet, Transit Bus	System – Real-Time Energy	Direct	V1G	Unified, Aligned
1937.1	Commercial – Fleet, Transit Bus	System – Real-Time Energy	Direct	V1G	Unified, Aligned
1937.2	Commercial – Fleet, Transit Bus	System – Real-Time Energy	Direct	V1G	Unified, Aligned
1945.1	Commercial – Fleet, Transit Bus	System – Renewable Integration	Indirect	V1G	Unified, Aligned
1945.2	Commercial – Fleet, Transit Bus	System – Renewable Integration	Indirect	V1G	Unified, Aligned
1946.1	Commercial – Fleet, Transit Bus	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
1946.2	Commercial – Fleet, Transit Bus	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
1948.1	Commercial – Fleet, Transit Bus	System – Renewable Integration	Direct	V1G	Unified, Aligned
1948.2	Commercial – Fleet, Transit Bus	System – Renewable Integration	Direct	V1G	Unified, Aligned
1949.1	Commercial – Fleet, Transit Bus	System – Renewable Integration	Direct	V1G	Unified, Aligned
1949.2	Commercial – Fleet, Transit Bus	System – Renewable Integration	Direct	V1G	Unified, Aligned
1957.1	Commercial – Fleet, Transit Bus	System – GHG Reduction	Indirect	V1G	Unified, Aligned
1957.2	Commercial – Fleet, Transit Bus	System – GHG Reduction	Indirect	V1G	Unified, Aligned
1957.3	Commercial – Fleet, Transit Bus	System – GHG Reduction	Indirect	V1G	Unified, Aligned
1958.1	Commercial – Fleet, Transit Bus	System – GHG Reduction	Direct	V1G	Unified, Aligned
1958.2	Commercial – Fleet, Transit Bus	System – GHG Reduction	Direct	V1G	Unified, Aligned
1958.3	Commercial – Fleet, Transit Bus	System – GHG Reduction	Direct	V1G	Unified, Aligned
1969.1	Commercial – Fleet, Transit Bus	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
1969.2	Commercial – Fleet, Transit Bus	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
1969.3	Commercial – Fleet, Transit Bus	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
1972.1	Commercial – Fleet, Transit Bus	System – RA, System Capacity	Direct	V1G	Unified, Aligned
1972.2	Commercial – Fleet, Transit Bus	System – RA, System Capacity	Direct	V1G	Unified, Aligned
1972.3	Commercial – Fleet, Transit Bus	System – RA, System Capacity	Direct	V1G	Unified, Aligned
1984	Commercial – Fleet, Transit Bus	System – RA, Flex Capacity	Direct	V1G	Unified, Aligned
1996	Commercial – Fleet, Transit Bus	System – RA, Local Capacity	Direct	V1G	Unified, Aligned
2041	Commercial – Fleet, School Bus	Customer – Bill Management	Indirect	V1G	Unified, Aligned
2042	Commercial – Fleet, School Bus	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
2042.1	Commercial – Fleet, School Bus	System – RA, Local Capacity	Direct	V1G	Unified, Aligned
2044	Commercial – Fleet, School Bus	Customer – Bill Management	Direct	V1G	Unified, Aligned
2047	Commercial – Fleet, School Bus	Customer – Bill Management	Indirect	V2G	Unified, Aligned
2050	Commercial – Fleet, School Bus	Customer – Bill Management	Direct	V2G	Unified, Aligned
2053	Commercial – Fleet, School Bus	Customer – Upgrade Deferral	Indirect	V1G	Unified, Aligned
2125	Commercial – Fleet, School Bus	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
2128	Commercial – Fleet, School Bus	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
2134	Commercial – Fleet, School Bus	System – Day-Ahead Energy	Direct	V2G	Unified, Aligned
2173	Commercial – Fleet, School Bus	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
2176	Commercial – Fleet, School Bus	System – RA, System Capacity	Direct	V1G	Unified, Aligned
2182	Commercial – Fleet, School Bus	System – RA, System Capacity	Direct	V2G	Unified, Aligned
2245	Commercial – Fleet, Small Truck	Customer – Bill Management	Indirect	V1G	Unified, Aligned
2245.1	Commercial – Fleet, Small Truck	Customer – Bill Management	Indirect	V1G	Unified, Aligned
2246	Commercial – Fleet, Small Truck	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
2246.1	Commercial – Fleet, Small Truck	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
2248	Commercial – Fleet, Small Truck	Customer – Bill Management	Direct	V1G	Unified, Aligned
2248.1	Commercial – Fleet, Small Truck	Customer – Bill Management	Direct	V1G	Unified, Aligned

2281	Commercial – Fleet, Small Truck	Customer -Renewable Self-Consumption	Indirect	V1G	Unified, Aligned
2284	Commercial – Fleet, Small Truck	Customer -Renewable Self-Consumption	Direct	V1G	Unified, Aligned
2293	Commercial – Fleet, Small Truck	System – Grid Upgrade Deferral	Indirect	V1G	Unified, Aligned
2296	Commercial – Fleet, Small Truck	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
2329	Commercial – Fleet, Small Truck	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
2329.1	Commercial – Fleet, Small Truck	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
2332	Commercial – Fleet, Small Truck	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
2332.1	Commercial – Fleet, Small Truck	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
2344	Commercial – Fleet, Small Truck	System – Real-Time Energy	Direct	V1G	Unified, Aligned
2353	Commercial – Fleet, Small Truck	System – Renewable Integration	Indirect	V1G	Unified, Aligned
2354	Commercial – Fleet, Small Truck	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
2356	Commercial – Fleet, Small Truck	System – Renewable Integration	Direct	V1G	Unified, Aligned
2365	Commercial – Fleet, Small Truck	System – GHG Reduction	Indirect	V1G	Unified, Aligned
2368	Commercial – Fleet, Small Truck	System – GHG Reduction	Direct	V1G	Unified, Aligned
2377	Commercial – Fleet, Small Truck	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
2377.1	Commercial – Fleet, Small Truck	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
2380	Commercial – Fleet, Small Truck	System – RA, System Capacity	Direct	V1G	Unified, Aligned
2380.1	Commercial – Fleet, Small Truck	System – RA, System Capacity	Direct	V1G	Unified, Aligned
2449.1	Commercial – Fleet, Large Truck	Customer – Bill Management	Indirect	V1G	Unified, Aligned
2450.1	Commercial – Fleet, Large Truck	Customer – Bill Management	Indirect	V1G	Fragmented, Aligned
2452.1	Commercial – Fleet, Large Truck	Customer – Bill Management	Direct	V1G	Unified, Aligned
2458.1	Commercial – Fleet, Large Truck	Customer – Bill Management	Direct	V2G	Unified, Aligned
2479	Commercial – Fleet, Large Truck	Customer – Backup, Resiliency	Indirect	V2G	Unified, Aligned
2482	Commercial – Fleet, Large Truck	Customer – Backup, Resiliency	Direct	V2G	Unified, Aligned
2497.1	Commercial – Fleet, Large Truck	System – Grid Upgrade Deferral	Indirect	V1G	Unified, Aligned
2497.2	Commercial – Fleet, Large Truck	System – Grid Upgrade Deferral	Indirect	V1G	Unified, Aligned
2497.3	Commercial – Fleet, Large Truck	System – Grid Upgrade Deferral	Indirect	V1G	Unified, Aligned
2500.1	Commercial – Fleet, Large Truck	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
2500.2	Commercial – Fleet, Large Truck	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
2500.3	Commercial – Fleet, Large Truck	System – Grid Upgrade Deferral	Direct	V1G	Unified, Aligned
2533	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
2533.1	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
2533.2	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
2533.3	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Indirect	V1G	Unified, Aligned
2536	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
2536.1	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
2536.2	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
2536.3	Commercial – Fleet, Large Truck	System – Day-Ahead Energy	Direct	V1G	Unified, Aligned
2548.1	Commercial – Fleet, Large Truck	System – Real-Time Energy	Direct	V1G	Unified, Aligned
2548.2	Commercial – Fleet, Large Truck	System – Real-Time Energy	Direct	V1G	Unified, Aligned
2548.3	Commercial – Fleet, Large Truck	System – Real-Time Energy	Direct	V1G	Unified, Aligned
2557.1	Commercial – Fleet, Large Truck	System – Renewable Integration	Indirect	V1G	Unified, Aligned
2557.2	Commercial – Fleet, Large Truck	System – Renewable Integration	Indirect	V1G	Unified, Aligned
2557.3	Commercial – Fleet, Large Truck	System – Renewable Integration	Indirect	V1G	Unified, Aligned
2558.1	Commercial – Fleet, Large Truck	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
2558.2	Commercial – Fleet, Large Truck	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
2558.3	Commercial – Fleet, Large Truck	System – Renewable Integration	Indirect	V1G	Fragmented, Aligned
2560.1	Commercial – Fleet, Large Truck	System – Renewable Integration	Direct	V1G	Unified, Aligned
2560.2	Commercial – Fleet, Large Truck	System – Renewable Integration	Direct	V1G	Unified, Aligned
2560.3	Commercial – Fleet, Large Truck	System – Renewable Integration	Direct	V1G	Unified, Aligned
2566.1	Commercial – Fleet, Large Truck	System – Renewable Integration	Direct	V2G	Unified, Aligned
2566.2	Commercial – Fleet, Large Truck	System – Renewable Integration	Direct	V2G	Unified, Aligned
2566.3	Commercial – Fleet, Large Truck	System – Renewable Integration	Direct	V2G	Unified, Aligned
2569.1	Commercial – Fleet, Large Truck	System – GHG Reduction	Indirect	V1G	Unified, Aligned
2569.2	Commercial – Fleet, Large Truck	System – GHG Reduction	Indirect	V1G	Unified, Aligned
2569.3	Commercial – Fleet, Large Truck	System – GHG Reduction	Indirect	V1G	Unified, Aligned
2572.1	Commercial – Fleet, Large Truck	System – GHG Reduction	Direct	V1G	Unified, Aligned
2572.2	Commercial – Fleet, Large Truck	System – GHG Reduction	Direct	V1G	Unified, Aligned
2572.3	Commercial – Fleet, Large Truck	System – GHG Reduction	Direct	V1G	Unified, Aligned
2578.1	Commercial – Fleet, Large Truck	System – GHG Reduction	Direct	V2G	Unified, Aligned
2578.2	Commercial – Fleet, Large Truck	System – GHG Reduction	Direct	V2G	Unified, Aligned
2578.3	Commercial – Fleet, Large Truck	System – GHG Reduction	Direct	V2G	Unified, Aligned
2581	Commercial – Fleet, Large Truck	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
2581.1	Commercial – Fleet, Large Truck	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
2581.2	Commercial – Fleet, Large Truck	System – RA, System Capacity	Indirect	V1G	Unified, Aligned
2581.3	Commercial – Fleet, Large Truck	System – RA, System Capacity	Indirect	V1G	Unified, Aligned

ANNEX 6: POLICY RECOMMENDATIONS

Working Group participants submitted policy recommendations that were then discussed, clarified, elaborated, consolidated, categorized, and commented upon. This process took place over the course of about three-and-a-half months, including a survey of the Working Group on agreement, clarity and relevance of each of the recommendations (see Annex 2 for details of the process; see Annexes 8 and 9 for survey results in the form of text comments and numerical results). The overriding intent of this process was to create actionable and specific recommendations for the CPUC and other agencies, without getting too immersed in details, to allow a clear picture to emerge of the Working Group's answer to PUC Question (b).

This process resulted in 92 policy recommendations. The full set of policy recommendations with all information is available in the Policy Recommendations Database (see Annex 1 for further materials).

During the process of drafting this Final Report, there were about 150 additional comments on the policy recommendations put forward by participants, reflecting additional insights and understandings reached at the very end of the process, in addition to the comments from the policy survey given in Annex 8. These 150 additional comments are not reflected in the recommendations themselves due to timing constraints for further discussion and vetting, but are provided as supplemental material in an "Additional policy comments" tab of the Policy Recommendations Database.

The following information is included in the Policy Recommendations Database for each of the 92 recommendations.

- Recommendation #
- Policy action
- What success looks like
- CPUC Energy Division comments and proponent responses
- CPUC Energy Division on action already underway
- CAISO, CARB, and CEC comments
- Timeframe (short-term 2020-2022, medium-term 2023-2025, and long-term 2026-2030)
- Policy category
- Secondary policy category (if any)
- Policy strategy tags
- Use case tags
- Relevant use cases
- Lead agencies/entities
- Supporting agencies/entities
- Metrics – how to measure success
- Barriers to implementation
- Existing relevant policy forums and/or decisions
- Notes
- Submitted by (may be one participant or multiple participants who worked together)

There are many possible ways of presenting and using the database. The database may be sorted, filtered, organized, and cross-referenced according to any of the above fields.

The following table gives the full text of the “policy action” field of the database, along with the recommendation number used to identify each recommendation in the database. The text of these recommendations in Tables 8-13 in Section B of the main report has been shortened from the full text versions given here to enable consistent and condensed presentation in Section B.

Rec #	Policy Action
1.01	Rate design for demand charge mitigation to be enabled by stationary battery storage coupled to EV charging
1.02	EV drivers across all sectors must be guaranteed direct access to their utilities' time-variant (e.g. TOU) rates, which are cost-competitive especially during off-peak periods, in order to both capture the value from currently "favorable" use-cases and unlock the value of currently "unfavorable" use-cases. To achieve this objective, utilities must be allowed the option to own and/or operate at least a portion of the charging stations across all sectors (e.g. residential, commercial workplace, commercial public destination, commercial public commute, MDHD), so their rates are directly available to EV drivers.
1.04	Establish EV TOU rates that don't require separate/submetering (significant customer cost). Allow vehicle data to be used as input to utilities for settlement to customer. Also- having a standardized TOU rate format across IOUs and other LSEs would be helpful.
1.05	The pricing signal received by EV customers (drivers and/or site hosts) at any particular time of day should be relatively consistent (not necessarily identical) across different sectors and price-setting entities, to ensure effective capturing and realization of value from EV flexible load. For example, charging at 2pm within the same geographical region should not be deemed "off-peak" on one IOU rate but "partial-peak" on another IOU rate or CCA rate. Harmonizing different EV rates by different entities, so they are consistent in any given time window, is important for customers to adjust their charging behavior and develop healthy, predictable, and robust charging habits. At the very least, different price-setting entities should agree on the time window where "off-peak" rates apply.
1.06	The pricing signal received by the EV and that received by the EVSE should be aligned and consistent (not necessarily identical) with one another and should incentivize/disincentivize the same charging/discharging action, to ensure effective capturing and realization of value.
1.07	Create an "EV fleet" commercial rate. Allows C&I customers to switch from a monthly demand charge to a more dynamic rate structure (e.g. average daily demand, dynamic TOU)
1.08	If dynamic rate is unavailable, increase the differential between standard and EV TOU Off-peak Charging rate (delivery portion)
1.09	Utility tariffs allow for customers with on-site solar and/or storage to utilize commercial EV rates. This would allow commercial customers, particularly transit agencies, to power charging with on-site solar and still take advantage of lower costs available for VGI-specific rates.
1.10	Improve Optional Residential and Commercial TOU rates designed to encourage EVs (e.g., whole house rate), fund outreach efforts on the rate, and set target to secure 60% level of participation TOU rates designed for EVs with high levels of participation. Optional whole house TOU rates that are better for EVs and the other electricity use (in almost all cases) compared to default TOU rates; similar is true for commercial optional TOU rates; increased utility and non-utility marketing of these optional rates is needed to reach large scale VGI adoption (60% participation rate is two maybe three times current levels for option whole house rates).
1.11	Develop a rate design and a standard implementation guide for utilities to provide real-time price and event (control) signals to EVSEs, Charging Station Management Systems (CSMSs), and EV drivers.
1.12	Alternative Approaches to Submetering for TE in Homes. Given the many challenges faced by EV submetering over the last decade for homes, a new approach is needed. Eight years ago, when the push for submetering began, attractive time variant rates were not available for homes. Today, residential time variant rates exist and participation rates in them are increasing. As a result, the use of whole house, time variant rates and AMI meters have captured many of the proposed benefits of submetering (e.g. off-peak use of electricity). Whole house rates are applicable for all types of DERs

	and for DR too, and knowing which appliance provided the export or load shift is not important. The use of whole house rates and meters for all load with all DER's helps minimize costs to the utility by keeping IT processes simple, reduces duplicative networking costs by using the existing AMI meter, and reduces customer confusion and costs especially for low- income customers. Measuring carbon reduction can be done with LCFS incremental credits or other means.
1.13	Retail EV charging rates should be reflective of the realistic cost of energy generation, delivery, GHG, and other relevant value streams. Unless proven necessary in select circumstances, all EV charging rates should be time-variant, starting with default TOU rates that contain three or four tiers (super-off-peak; off-peak; partial-peak; peak) to maintain simplicity, and then by enabling optional, more complex alternatives such as dynamic rates that pass through increasingly granular time- and location-specific price signals.
1.15	Prompt CPUC approval of time-varying EV rates applications
1.16	Expand the definition of eligible customer-generator under current NEM tariff option to include customers that own and/or operate EVs and/or EVSE with bi-directional capabilities. In addition to an EV export bill credit (under NEM or another framework), a supplemental credit should be considered for the environmental component, such as one based on similar tools implemented for the SGIP GHG signal to determine marginal emissions rate (i.e., WattTime)
1.17	[Gridworks note: this appears to be significantly different than the original 1.17, "Create tariffs specific to electric school buses that potentially account for V2G." Resolution uncertain.] In addition to an EV export bill credit (under NEM or another framework), a supplemental credit should be considered for the environmental component, such as one based on similar tools implemented for the SGIP GHG signal to determine marginal emissions rate (i.e., WattTime).
1.18	Establish voluntary Critical Peak Pricing tariffs for non-residential charging that pass through reduced TOU rates except during event-based flex alert or critical peak periods, where on-peak hours pass through significantly increased prices. This could include creation of a portfolio of programs spanning a "Rush hour rewards"-style peak time rebate incentive program for EV owners/fleets/EVSPs who respond to utility signal to limit charging during critical peak periods, or a Public Charging incentive/payment or future free charging session for customers that agree to not to charge during critical peak periods.
1.19	Performance-based ratemaking
1.20	Create tariffs specific to medium/heavy duty vehicles and fleets (rideshare, for example).
2.01	Require utilities to broadcast signals to a DER marketplace of qualified vendors (curtailment and load)
2.02	This policy is part two of a two-step recommendation that depends on the first part (V2G pilot) being successful enough to warrant investigating this second part. Pending a successful pilot, V2G systems become eligible for incentives in order to create a "level playing field" for DERs that provide similar services. The current SGIP program could inform V2G incentive structure so that performance requirements, pricing, and other elements remain consistent where applicable and become modified when appropriate. For the first step, assessing potential incentive structures could be part of a larger scope for broader V2G pilots or be added to Fermata policy recommendation 7.04. A similar path could also be taken for V1G albeit with a separate scope. See supplemental Fermata V2G Pilot + Incentive Presentation.
2.03	Establish "reverse EE" rebates (pay for performance?) for EVSE installations that build permanent midday load
2.04	Enable customers to elect BTM load balancing option to avoid primary or secondary upgrades, either if residential R15/16 exemption goes away, or as an option for non-residential customers
2.05	Require managed charging capability in utility customer programs, incentives, and DER procurements.
2.06	Require all government-funded charging infrastructure to have smart functionality.
2.07	Create a strategic demand reduction performance incentive mechanism, include EVs as technology that can reduce and shift peak demand.
2.08	The CPUC and CEC should consider coordinated utility and CCA incentives for EVs, solar PV, inverters, battery energy storage, capacity, including panel upgrades, and EV charging infrastructure to support

	resilience efforts in communities impacted by PSPS events. Coordinated incentives should be designed with resilience and equity in mind, providing the benefits of these technologies to customers directly impacted by PSPS events, as well as CARE/FERA, medical baseline, and/or low-income customers.
2.09	Leverage existing pilots in the state to identify major bottlenecks for increasing deployment and reducing costs. Encourage utilties, in partnership with private entities, to establish dedicated programs or sub-programs (under MDHD) for School Bus charging solutions
2.11	Create an EV Dealership VGI upfront incentive program whereby utilities can reward dealers for installing or enabling VGI functionality at point of sale. Examples could range from simple to complex: --Charge timer setting + EV TOU sign up (simple) --Service reminder for future charge timer period adjustments (less simple) --Real-time charging settings, with $/MWh thresholds (more advanced) --Voltage control (even more advanced, enhanced by V2G) --Discounted/rebated home L2 chargers if preprogrammed for defined VGI services (could be cofounded by utility & third party EVSP providers)
2.12	Allow V1G and V2G to qualify for SGIP to level the playing field with incentives for other DERs, but V1G would get recognition and likely less incentive compared to V2G based on the permanent load shift logic used in the AB 2514 Storage mandates. An interim step would be for SGIP to fund pilots in various market segments to test details (e.g. customer response to different incentive levels, how much to provide to V1G compared to V2G or V2B, whether V1G and V2G can perform like other DERs). The best precedent is the AB 2514 Storage Procurement requirements which allows V2G to qualify and allows a few types of permanent load shift to qualify such as ice storage (unidirectional power flow as is V1G). Note that the AB 2514 program is fully subscribed so modifying SGIP seems more feasible. Creating value for VGI in existing programs such as SGIP will accelerate VGI.
2.13	Allow V1G (Smart Charging/Managed Charging) to be counted as storage for Storage Mandate
2.14	Prioritize and properly document and implement one or more of the cost-effective use-cases for every transportation electrification plan, project, or program that (1) is supported or subsidized by public funds; (2) is applied at commercial scale (200+ EVs or 100+ EVSEs); and (3) is to be deployed in the next 1-5 years. Every TE program or project meeting the three criteria above must include the deployment of one or more cost-effective VGI use-cases.
2.15	Incentive(s) for construction projects with coincident grid interconnection and EV infrastructure upgrade
2.16	Incentivize multiple VGI communication control pathways and cloud aggregators (similar to other smart appliances and Internet of Things (IoT)) to stimulate healthy competition amongst VGI aggregators and service providers, reduce networking costs and not favor EV or EVSE centric VGI communication business models and put any VGI communication requirements (TBD) on the cloud aggregators not on the EVSE or EV. Cloud-based aggregators can handle many open and proprietary standards from automakers or charging networks, easily accommodate upgrades to standards and allow utilities to use one or two open standards to communicate with the aggregator. The multiple cloud aggregator model is based on how it works with smart thermostats and smart inverters, and leverages existing communication platforms (e.g. Wi-Fi [if reliable] or vehicle telemetry) to keep networking costs low.
2.17	Enable customers, via Rules 15/16 or any new tariff for EV make-ready infrastructure, to elect certified behind the meter load management technologies to avoid primary and / or secondary upgrades, and make the Point of Common Coupling the focus of capacity assessments rather than the aggregate capacity of individual behind the meter assets such as EVSEs and other DERs. Behind the meter load management systems are proven, UL-certified and NEC-approved solutions that will significantly reduce net economic costs avoiding unnecessary distribution system upgrades. This policy recommendation should ultimately be applied on a technology agnostic basis, but VGI-based upgrade avoidance is a relevant near-term use case that can be implemented as an option for utility EV infrastructure investments.
2.18	Incentivize multiple EVs using a single charging station (e.g., chargers that power share / sequence) to keep charging load spread across as many vehicles as possible.

2.19	Create and fund utility programs, similar to programs to help economic development decades ago, to site higher level kW charging (AC or DC) for commercial applications (e.g. fleets, public DCFC, workplace charging) in the best public-and private access locations to encourage high utilization and long-term planning by using grid planning studies (see policy 7.11), routes, demographics and other tools with peer review by planning agencies. Even though grid maps are available now to help with siting charging stations, this program would provide more tools and greater assistance to site hosts and project developers. The initial phase could start with a pilot program.
2.20	Consider funding opportunities and rate design reform for stationary batteries co-located with DC fast chargers (DCFC) to reap grid benefits and potentially improve economics of near-term DCFC installations with low utilization.
2.21	Public charger ancillary services program: --Provide a performance-based incentive for building owners, or EVSP providers, who recruit a certain fraction of EV drivers to opt in to allowing their EV to temporarily provide grid services (e.g. regulation) while parked. --Long-term contract through procurement
2.22	Non-wires alternative competitive procurement issued (RFO) targeted to EVs/EVSPs that can limit demand during peak times
2.24	Align LCFS smart charging framework IOU TOU rates.
3.01	Authorize new tariffs in CAISO ESDER Phase 4 that allow utilities to pay V1G aggregators to use managed charging to reduce the local distribution grid impacts of EV charging.
3.03	Enable aggregations of EVs on managed charging to participate as resources in real-time energy markets and ancillary services market.
3.04	Need clarity and conclusive decision on what pathway (PDR vs. NGR) will enable V2G resources to offer Day-Ahead Energy and RA System services, in order to both capture the value from currently "favorable" use-cases and unlock the value of currently "unfavorable" use-cases. If PDR is the chosen pathway (preferred), then need clarity on the timeline and roadmap to get there.
3.05	CAISO allows for BTM EV charging, single site or part of an aggregation, to participate in Ancillary Service markets, particularly Frequency Regulation, without need for energy market participation. This could be under an alternative PDR participation model or a new capacity-only designation for resources providing Ancillary Services. Telemetry requirements should be similar to existing requirements for DER Aggregations.
3.07	Coordinated effort by state agencies and IOUs and other LSEs to establish market rules and participation options for separately metered V2G customers. Take learnings from existing V2G and other DER pilots and demonstration projects to establish market rules and new utility billing mechanisms that would allow for customers/aggregators to access wholesale market and Resource Adequacy revenues that are unavailable today for any grid exports. Pilot additional demonstration projects to the extent they will result in lasting operational/accounting standards. This will ultimately need to be addressed in CPUC proceedings, likely a new MUA proceeding focused on specific actionable accounting rules rather than the general guidelines that currently exist.
4.01	Initiate a voluntary task-force to help gather, model, and analyze data related to these use-cases' benefits and costs. Prioritize the analysis of these use-cases within the VGI Data Program initiative proposed by CalETC in the DER Roadmap
4.02	Any Level 2 EVSE sold within the next 2 years must be capable to provide energy services, i.e. can respond to an external data source to delay, reduce or initiate charging at a specific time for a specified duration based on an event or price signal and user-defined criteria. In order to meet this requirement, the EVSE must be able to support, directly or through a remote (cloud) service, OCPP, OpenADR, or IEEE 2030.5.
4.03	Better understand the trend toward 10-19 kW home charging and explore long-term solutions to mitigate the impact (e.g. studies, pilots, task forces looking at incentives and disincentives) the (disproportionate) grid impacts of high-kW (e.g., 10-19 kW) charging in residences Create studies or task forces to examine incentives and disincentives including rate reform, rebates, and special charges. Studies or pilots are recommended in the early years leading to rates, tariffs, or incentives as solutions.

4.04	Perform detailed cost-effectiveness analysis for specific VGI use-cases in programs/measures that are ratepayer funded, in order to quantify the impact on EV customer, ratepayer, utility, and society at large. Important considerations to guide the implementation of this task include: (1) Cost-effectiveness valuation should include use-cases under both Direct and Indirect approaches. (2) For every use-case: Parties that scored the said use-case as "favorable" are strongly encouraged to support in the detailed cost-effectiveness analysis (while mindful of anti-trust concerns); not providing such support may risk de-favoring and therefore de-prioritizing the said use-case. (3) The VGI cost-effectiveness valuation methodology should be consistent and aligned with the any cost-effectiveness valuation methodology applied to the larger context of TE programs as a whole; VGI measures ashould not be evaluated in isolation. (4) consider existing cost-effectiveness metrics such as Avoided Cost Calculator and Ratepayer Impact Measure (RIM). (5) ensure only incremental costs of VGI measures are considered.
4.06	Use EPIC, ratepayer, USDOE, and/or utility LCFS funds ($2-4M) for an on-going, multi-year program to convene VGI data experts to study a wide array of VGI topics, including lessons learned from past and on-going projects, paying for new data sources and analysis and quantifying net value of VGI and other DERs (e.g. finishing VGIWG subgroup B and D quantitative net value analysis). Existing and on-going VGI data from CPUC, CEC, CARB, DOE approved, or funded programs and projects would be included in this program. Other data experts and data sets from automakers, national labs, charging network providers would be hired (optionally participate in this data expert collaboration). Variation of this idea is in the draft CEC DER Roadmap.
5.01	Bring automakers to the table to agree to allow limited discharge activity for resilience purposes to be kept under warranty if customers are willing to pay for upgraded bi-directional charging hardware.
5.02	Pilot funding for EV backup power to customers not on microgrids. This includes: (1) Set a state goal (floor) of having EVs providing emergency backup generation during PSPS events: At least 100 EVs by mid 2021 and at least 500 EVs by mid 2022. This could be implemented as one pilot or a portfolio of pilots across California. (2) Utilities to consider the feasibility of EVs for emergency backup generation as part of their PSPS plans and resiliency solutions over the next 2-3 years. Per Recommendation 1, cost-effectiveness shall continue to be a major criterion for evaluating the feasiblity of EVs for backup generation.
5.03	Develop standards and requirements for buildings which will support the use of the EV's main power batteries for customer resiliency
6.03	Explicitly prioritize these use-cases to be included in the next cycle of PRP submissions by one or more of the IOUs and other LSEs, as well in the next phase of EPIC funding.
6.04	Drastically simplify NEM tariffs and streamline NEM applications for EVs; explore possibility for (simplified) NEM tariff specifically for EVs, in order to both capture the value from currently "favorable" use-cases and unlock the value of currently "unfavorable" use-cases. Along the same lines, strongly encourage better communication of EV TOU and NEM rates to the general public and other business entities.
6.07	Pilot funding for V1G / V2G for microgrid / V2M solutions. This includes: (1) Set a state goal (floor) of having 10 MW of EVs providing grid services to microgrids, including energy supply, capacity, or others services, in the near-term. One area of consideration would be to test an EV-powered microgrid at community centers in vulnerable communities. (2) Utilities should consider the feasibility of EVs for FTM grid services as part of their PSPS plans and microgrid frameworks.
6.11	Coordinate the development of interconnection and technical standards with the VGIWG effort.
7.01	Dedicate specific efforts that allow TNC/Rideshare drivers to reduce their costs by benefiting from utility and other publicly-funded programs and rates, in order to both capture the value from currently "favorable" use-cases and unlock the value of currently "unfavorable" use-cases. This includes, but is not limited to: (1) a clear pathway for TNC/Rideshare to participate in utility programs for commercial charging (DCFC and L2) and to benefit from make-ready infrastructure and charger rebates, including an option for dedicated or semi-dedicated (during specific periods of the day) chargers; (2) a clear pathway for TNC/Rideshare to participate in state-funded programs like CaleVIP; (3) guaranteeing direct access to utility rates for TNC/Rideshare drivers reliant on public charging, per Recommendation 11.0

7.02	Improve the allocation of LCFS credits as a mechanism to capture the benefits of GHG Reduction and Renewable Integration, such that: (1) EVs with higher VMT (e.g. rideshare, MDHV) earn higher amount of credits, regardless of the party claiming/filing for those credits (utilities, OEMs, etc.); (2) EV drivers or their designated/chosen agents have a streamlined process that enables them to claim these credits directly if they choose to; (3) at least 70% of the LCFS credits are guaranteed to be channeled back to the EV driver or their designated/chosen agent, regardless of the claiming/filing party. (In order to both capture the value from currently "favorable" use-cases and unlock the value of currently "unfavorable" use-cases.)
7.03	Leverage EPIC funding to pilot some use-cases in order to: (1) better understand realistic costs and implementation challenges; (2) identify concrete ways to reduce cost and streamline implementability. The pilots would cover both sectors Workplace and MUD. Among other activities: strongly endorse the "Distributed Energy Resource Solutions for Medium- and Heavy-Duty Electric Vehicle Charging" initiative launched by the CEC.
7.04	Create pilots to demonstrate V2G's ability to provide the same energy storage services as stationary systems. Additionally, let V2G systems participate in pilots for stationary energy storage. These pilots would utilize, commercially deployed V2G systems - see "Group A" use cases in recommendation #1.0 The purpose of the pilots is test V2G effectiveness in performing grid applications which are not currently accessible. These new "stackable" applications would be added to and complement base applications such as customer bill management which are accessible today.
7.05	Special programs and pilots for Municipal fleets to pilot V2G as mobile resiliency. V2G has particular value for municipal fleets as a mobile, resiliency response asset. This includes resiliency use cases and other use cases not contemplated in this work group such as ones related to disasters and emergencies. These could be piloted in a similar context as described in recommendation #2.
7.06	Grant funding opportunities can be amended to provide “plus-up” funding for DER arrangements that optimize grid conditions.
7.07	Develop a demonstration pilot that defines a means, based on existing open standards, that allows Aggregators, EV Network Providers and Charge Station Operators to dynamically map the capacity and availability of EVSE resources to local coordination areas – from transformer to feeder to substation.
7.09	VGI Acceleration Proposal using EPIC, ratepayer, USDOE, and/or utility LCFS funds ($50M) in many competitively bid large-scale demonstrations of promising VGI use cases to provide private sector executives with the data they need to scale up VGI efforts (e.g., validate consumer acceptance, incentive levels, security, net value, and communication pathways). to CEC to fund The funding solicitation would select many advanced promising use cases from the VGIWG process in a diverse set of charging market segments, types of EVs, types of charging, types of VGI communication to validate whether they meet key energy system goals of affordability, resiliency, security, flexibility, and reliability, and address market barriers such as cost, valuation and capability.
7.11	Utility - agency study funded to understand the impact on the distribution grid and generation system from light-, medium-, heavy-duty and non-road EVs forecasted out to 2040 in VGI and non-VGI scenarios based, at minimum, on over 10 existing or planned mandates from CARB and SCAQMD to meet California’s 2045 carbon neutral goal (with a focus on port and warehouse/factory districts). Many planned and existing CARB and AQMD regulations require increased TE adoption from 2030 to 2040, and CARB’s upcoming SB 44 strategy will provide more guidance. However, the current AB 2127 looks to 2030 only. This study would focus on impact of all these regulations under different scenarios on the distribution system especially for the goods movement industry and make recommendations. It would coordinate many currently uncoordinated efforts including utility T&D planning processes, the IRP, and agency efforts such as the SB 44 and AB 2127 studies as well as link to policy recommendation 2.19. Grid planning for a decarbonized world needs to start to prepare.
7.13	Create a mechanism which allows for quick approval of demonstrations for technology and to determine market interest
7.14	Increased pilots exploring shared charging infrastructure for commuter-based fleets, both public and private. This should include medium distance transit commuter buses that operate in morning and

	afternoon/evening as well as the growing fleet of tech company and other corporate shuttles. Pilots should include provisions for managed charging and potential provision of market services and V2G.
8.01	Incentives for Title 24 new construction -- MUDs and some C&I (especially workplace and large destination) parking facilities
8.02	Finalize submetering protocols/standards to increase accessibility to more favorable EV TOU rates.
9.01	Optimize CALGreen codes for VGI and revise to require more PEV-ready parking spaces and expand to existing buildings. For buildings that go significantly above the requirements, incentives can be made available, similar to the California Advanced Homes Partnership.
9.02	Create public awareness and education programs and materials on V2G systems and how to get them. This could particularly be focused toward government fleets.
9.03	Through TE plans, utilities develop coordinated ME&O budgets to inform EV customers of the lower cost of fueling EVs using dynamic rate options and other VGI opportunities. This ME&O for VGI ramps up in tandem with overall TE efforts.
10.01	Prevent policies that make VGI a primary goal over the needs of drivers or CARB and AQMD mandates to support 2045 carbon neutrality and 2030 air quality requirements. In VGI efforts, do not add net cost to users of non-road EVs or light-, medium- and heavy duty EVs or hinder TE adoption especially among disadvantaged or rural consumers. Fund efforts to study and monitor this issue. As noted in policy 7.11 many existing and upcoming state and local regulations are mandating TE and utilities are obligated to serve all loads especially loads needed to meet these new goals. State agencies should work to support state goals for adoption of light-, medium- and heavy-duty EVs as well as non-road TE including TE with non- flexible load. As a result, VGI is an important supporting goal but not the only goal. Some types of TE use cases have little ability to be flexible and accommodate VGI. Planning for and serving efficient TE load is more important than VGI when the goals conflict.
10.02	Use the proposed Joint IOU VGI Valuation Framework (6 dimensions) and associated use-cases to reference, articulate, and communicate about VGI in policymaking across CA state agencies. The 6 dimensions (Sector, Application, Type, Approach, Resource Alignment, and Technology) can be used as a starting point to reference specific VGI use-cases, with additional details added as necessary. Specifically, strong recommendation to use the Joint IOU VGI Valuation Framework as the foundational framework for VGI in the Transportation Electrification Framework under the DRIVE OIR.
10.03	Across all agencies: Public funding of VGI use-cases should prioritize initiatives, projects, and programs that involves formal collaboration between at least one load serving entirt (utility or CCA) and at least one automaker or EV service provider.
10.04	The six state agencies coordinate and maintain consistency on TE and VGI across the different policy forums (see CalETC letter) and state policy goals with no duplication of regulation on TE and VGI, clear roles, vision and deadlines on VGI, regular and frequent coordination at staff and executive levels and priority on state TE goals over VGI. The six agencies are CPUC, CEC, CARB including LCFS, CAISO, CDFA's Division of Measurement Standards and GO-BIZ.
10.05	The six state agencies should recognize that stakeholder's specialized TE and VGI staff resources are limited and avoid workshops and hearings on the same day, and hold no more than 2-3 VGI and TE events per month. The six agencies are the CPUC, CEC, CARB including LCFS, CAISO, CDFA's Division of Measurement Standards and GO-BIZ.
10.06	Develop a Virtual Genset model and reference implementation pilot.
10.07	Avoid over-regulation of EVSE specifications
10.09	Encourage multiple open standards for VGI communication especially for utilities, charging networks, cloud aggregators, and site hosts to encourage lower cost solutions but recognize that, similar to smart appliances and the Internet of Things approach, cloud aggregators can handle both open and proprietary standards for VGI communications. Using cloud aggregators and multiple standards also encourages market innovation, competition between automakers and charging networks, allows lower cost by piggybacking on existing communications2, and leverages the universal connectivity of existing intelligence in the EV, EVSE, phone or home Wi-Fi. To incentivize open standards for charging connectors, to reduce vendor lock-in at site hosts, and for VGI communication use incentives or

	voluntary codes, like Green Building Code or LEED, in California Rules, Titles and utility programs. (The exception is complying with CARB and CDFA regulations on payment, accuracy, signage, and access).
10.10	A ML EVSE or Charging Station must be capable to provide energy services and may provide regulation services (volt/VAR, frequency, pf). The EVSE or Charge Station Management System must support OCPP or an equivalent standard that supports an external energy management system that supports grid interactions.
10.11	A HL Charging Station (>500 kVA) must provide energy services and must be capable to provide regulation services (VVO, frequency response).
10.12	Establish a voluntary task-force to convene on regular basis to discuss technological barriers; submit semi-annual update reports to relevant CA state agencies (CPUC, CEC, CARB, and CAISO) every 6 months, including potential recommendations on consensus items. This technical task-force can potentially also address topics related to interoperability and communication pathways and protocols.
10.13	Establish a voluntary task-force to convene on regular basis to discuss barriers related to retail market design; submit semi-annual update reports to relevant CA state agencies (CPUC, CEC, CARB, and CAISO) every 6 months, including potential recommendations on consensus items.
10.14	Establish a voluntary task-force to convene on regular basis to discuss barriers related to wholesale market design; submit semi-annual update reports to relevant CA state agencies (CPUC, CEC, CARB, and CAISO) every 6 months, including potential recommendations on consensus items.
10.15	Establish a voluntary task-force to convene on regular basis to discuss barriers impacting customer adoption and participation; submit semi-annual update reports to relevant CA state agencies (CPUC, CEC, CARB, and CAISO) every 6 months, including potential recommendations on consensus items.
11.01	Reduce or eliminate demand charges for DCFC, but scale up with utilization to create more demand-responsive rate.
11.02	Institute shared benefit structure for LCFS or similar funding between host site and EV driver/operator/owner
11.03	Permit streamlining
11.04	Investigate ADA and other obstacles to charger installation at MUDs and some high-density C&I locations
11.05	Incentives for new construction -- public parking lot projects

ANNEX 7: POLICY STRATEGY TAGS FOR POLICY RECOMMENDATIONS

Policy Categories

1	Reform retail rates
2	Develop and fund government and LSE customer programs, incentives and DER procurements
3	Design wholesale market rules and access
4	Understand and transform VGI markets by funding and launching data programs, studies and task forces
5	Accelerate use of EVs for bi-directional non-grid-export power and PSPS resiliency and backup
6	Develop EV bi-directional grid-export power including interconnection rules
7	Fund and launch demonstrations and other activities to accelerate and validate commercialization
8	Develop approve and support adoption of technical standard not related to interconnection
9	Fund and launch market education & coordination
10	Enhance coordination and consistency between agencies and state goals
11	Conduct other non-VGI-specific programs and activities to increase EV adoption

Policy Strategy Tag	Cat 1	Cat 2	Cat 3	Cat 4	Cat 5	Cat 6	Cat 7	Cat 8	Cat 9	Cat 10	Cat 11
01 Reduce operating costs	1.01 1.02 1.04 1.07 1.08 1.09 1.10 1.11 1.12 1.15 1.18 1.19	2.02 2.09 2.11 2.12 2.16 2.18 2.19 2.24				6.03	7.01			10.01 10.09	11.01 11.02
02 Reduce deployment (capital) costs	1.02	2.04 2.11 2.17 2.18 2.19		4.03 4.04	5.02	6.07	7.14	8.02	9.01	10.07 10.09	
03 Reduce societal costs / maximize benefits	1.13 1.18	2.02 2.03 2.04 2.12 2.16 2.17 2.18 2.19		4.04	5.02	6.03 6.07	7.01 7.02		9.03	10.09	
04 Reduce on-peak demand	1.01 1.04 1.07 1.08 1.09 1.10 1.11 1.13 1.15 1.18	2.02 2.03 2.05 2.06 2.07 2.11 2.12 2.13 2.17 2.20 2.21	3.01 3.03	4.02		6.10 6.11				10.06 10.10 10.11	

		2.22 2.23									
05 Support indirect managed charging	1.04 1.05 1.06 1.07 1.08 1.09 1.10 1.13 1.15 1.18	2.03 2.09 2.11					7.14				
06 Support direct managed charging	1.01 1.04 1.06 1.07 1.08 1.09 1.10 1.11 1.13 1.14 1.15 1.16 1.17 1.18	2.01 2.04 2.05 2.06 2.07 2.09 2.11 2.13 2.21	3.01 3.03 3.04 3.07	4.02 4.06	5.01	6.11	7.04 7.05 7.09 7.14			10.06 10.10 10.11	
07 Support Demand Response market	1.01 1.11 1.18	2.01 2.05 2.06 2.07 2.09 2.11 2.13 2.21	3.03 3.04	4.02 4.06		6.11	7.09			10.06 10.10 10.11	
08 Enhance resiliency & service restoration	1.14 1.16	2.02 2.08 2.11 2.12 2.21			5.01 5.02 5.03	6.07	7.03 7.05				
09 Provide wholesale market services	1.01 1.17	2.03	3.03 3.04 3.05 3.07		5.01	6.11	7.04			10.06 10.10 10.11	
10 Accelerate TE	1.02 1.05 1.06 1.12 1.13 1.20	2.09 2.10 2.15 2.17		4.04 4.06	5.02		7.01 7.02 7.07 7.09 7.11 7.13	8.01 8.02	9.02 9.03	10.01 10.02 10.03 10.04 10.05 10.12 10.13 10.14 10.15	11.01 11.03 11.04 11.05
11 Grid planning		2.04 2.17 2.18 2.19 2.20		4.03 4.04			7.11			10.01	

12 Level playing field for all DERs		2.04	3.07	4.04			7.06		9.03		
13 Support future distribution services market	1.14 1.16 1.17	2.01 2.02 2.12 2.21	3.01 3.03 3.04		5.01	6.11	7.07			10.10 10.11	
14 Streamline process or permits		2.04 2.17		4.06		6.03 6.04	7.01 7.02	8.03	9.01	10.02 10.07	11.03 11.04
15 Accelerate understanding / accelerate business decisions	1.05 1.06	2.09 2.10 2.14	3.04	4.01 4.04 4.06	5.02	6.03 6.07	7.01 7.03 7.04 7.09 7.11 7.13 7.14	8.02	9.02 9.03	10.06 10.12 10.13 10.14 10.15	11.04
16 Reduce program development costs and maximize resource leveraging		2.16		4.04	5.02	6.07	7.01 7.13			10.03 10.04 10.05 10.07	

ANNEX 8: SURVEY COMMENTS ON POLICY RECOMMENDATIONS

A total of 28 responses to the policy survey were received. Responses were received from California Electric Transportation Coalition, California Energy Storage Alliance, Charlie Botsford (independent), Electrify America, Enel X, Energy Innovation, ENGIE Impact, Evgo, Fermata, Ford, GM, Greenlots, Kitu Systems, Los Angeles Department of Water and Power, the Working Group's MHDV Team (see Annex 2 for composition), Natural Resources Defense Council, Nuvve, Public Advocates Office, Peninsula Clean Energy, Pacific Gas and Electric, Plug-In America, Small Business Utility Advocates, Southern California Edison, San Diego Gas & Electric, Sumitomo, Tesla, Tim Lipman, and Union of Concerned Scientists. The identities of respondents in survey results are being kept anonymous.

The individual survey submissions are available for viewing in the Policy Recommendations Database, including all the individual comments for each policy recommendation.

The comments from Question #4 of the survey are given in this annex. Question #4 was:

> Any other comments on this recommendation? Include any notes about how you see this recommendation connected to any of the other recommendations, including overlaps or complementarities.

The table below gives all survey comments received. Some recommendations have multiple comments that are identical or similar—this is due to multiple participants submitting the same or similar comments, perhaps through collaboration on their responses, and these duplicates have been retained on purpose to show every comment received. There are also typos and grammar issues in these comments that have not been corrected.

Rec #	**Survey Comments**
1.01	• With respect to EV charging, the cost of battery energy storage is almost never justified as a strategy to shore up the business model, even with exorbitant demand charges. Demand charges are inconsistent as applied across the three California IOUs, unfair to customers, and not justified. The majority of utilities across the US do not apply demand charges. The most appropriate policy recommendation would be revamped demand charges so that they are consistent and can be justified. • This relates to recommendation 7.06, which suggests incentives for stationary battery storage coupled to EV charging. It also relates to a recommendation we submitted but I do not see in the list of recommendations: "Reduce or eliminate demand charges for DC fast chargers (DCFC), but scale up with utilization to create more demand-responsive rate." In terms of clarity issues, stationary battery storage coupled to EV charging should mitigate demand charges without changes to rate design, so it's unclear what this recommendation is suggesting. In situations where co-located stationary battery storage is not possible, rate design to mitigate demand charges might be necessary. • SBUA submits that charge mitigation via stationary battery storage is vital for businesses which can otherwise be responsible for very high demand charges. • VGI goals may be inhibited if storage coupled with EV charging is needed; many public charging locations cannot accommodate storage or have to reduce the number of chargers open to the public to accommodate storage • We would support this if it leads to lowering demand charges. • SMUD has a pilot on-going to understand the issues • SMUD has a pilot on-going to understand the issues • SMUD has a pilot on-going to understand the issues

	• Not quite sure why a new rate design is needed here, needs a little more explanation • Most recent EV rate designs in California have looked to reduce demand charges. Without demand charge management, demand charges are cost prohibitive for public charging. These new rates actually reduce the potential benefits from this policy action. To our knowledge, the proposed recommendation is already possible. However, we understand that the nuance of this recommendation is that customers be given an incentive to continually reduces demand, such as having daily rather than monthly demand charges. How does the end goal of this recommendation differ from policy action 1.07? • Non-coincident demand charges in existing, generic commercial rates (not specific to EV charging) seem to already provide the price signal that would enable the use case being described here (using site-integrated batteries to manage demand charges). So, more clarification is needed on the ask. • Behind the meter storage can lower impact of demand charges however unclear if a specific rate for batteries will unlock its full potential. Batteries, if not leveraged for lowering demand, have more value through bilateral or RTO market-based services. The policy is clear but will have little impact on lowering demand charges for EV load beyond a normal dynamic rate. If flexible devices we able to be aggregated, agnostic of the technology, this would be a powerful way to leverage flexible loads behind the meter. E.g. heat pumps, EVs, and batteries. • Metrics should also include energy reduced from peak • SMUD has a pilot on-going to understand the issues • No comment on this recommendation. In general, non-coincident demand charges are an issue and the flattening of differential in the TOU rates. • Doesn't contribute much more than existing efforts. Does this mean a rate with high demand charges that battery storage can be used to mitigate, or a rate with low demand charges and presumably high peak/off-peak differentials? Our standard C&I rates are the former; Commercial EV rate is the latter.
1.02	• What is being asked in this recommendation? Is it asking to pre-approve utility ownership? Hard to answer this without clarifying what is recommended here. • IOU ownership of infrastructure is difficult to justify because of extraordinarily high installation costs. For example, the SCE Charge Ready, the SDG&E Power Your Drive, and the PG&E Charge Network programs had bloated costs in excess of $15K per port. This is approximately 3X times the cost of EV infrastructure installed by anyone not a utility. California ratepayer money would be much better spent by giving rebates or incentives to site hosts. Keep the IOUs away from EV infrastructure ownership. • This opens up a bigger question of utility ownership, and perhaps more importantly, the idea that EV drivers pay exactly the cost of electricity through charging stations. I agree conceptually that there should be time-varying rates for as many customer classes as possible but I think this recommendation goes a bit too far into other domains and conflates some issues. • Not clear why IOUs must be allowed to own and/or operate at least a portion of charging stations. • VGI goals are best served if charging station ownership and operation are left to the private, competitive market, including the setting of rates. Utility ownership may halt private investment and create a ratepayer burden given a guaranteed rate of return for utilities in excess of what the competitive market may otherwise accept. Charging is not a natural monopoly. • We generally support having TOU available but the research /data available for the case on utility ownership needs more. Keeping rates simple for all EV drivers is best. • This would require changing the deregulation of charging networks • would require changing the deregulation of charging networks; we might be misunderstanding this one • Rates charged by third-party operators are currently not regulated products. • Concur with CPUC comment -- not clear why ownership by IOUs is necessary to pass through dynamic rates • We agree that there are cost parity issues between residential and commercial charging. However, we disagree that the approach to solve this issue is to pass on such costs to other ratepayers. Parties have argued that EVs should be further subsidized because EVs have created downwards pressure on rates by increasing load. However, most downwards pressure on rates studies have compared total EV load vs. current ratepayer funded programs. The ratepayer funded programs represent only a fraction of the total EV population, and therefore, while EVs may have generally caused downwards pressure on rates

	so far, the marginal cost of a utility infrastructure-incented EV on a per EV basis may still far exceed the downwards pressure on rates it has caused. Moreover, price parity at the pump is a false dichotomy. Residential EV charging incurs additional costs to the driver in terms of purchasing and operating the EVSE. It is therefore arguably fair if EV drivers who publicly charge pay a surcharge related to the public EVSE's O&M costs. Of course, demand charges can increase public charging prices far beyond that of residential + O&M costs, but public charging does not necessarily need to have direct fueling costs equivalent to residential to be equitable. • Certain IOU programs might have site hosts / developers take service under TOU or a more advanced VGI rate, either as a requirement or by default, but we support the ability of site hosts / project developers to choose the rate or fee they pass through to drivers. • TOU prices signals should be passed through to drivers by default to realize the grid benefits and fuel cost savings that justify the investment of customer funds. Ownership is not inherently necessary for this, and should be stricken from the policy action description to clarify the core policy recommendation • Disagree with the proposal of utilities owning this type of infrastructure • would require changing the deregulation of charging networks • For public fast charging, direct time variant rates would be overly cumbersome and would not account for the cost EVSPs must also factor in outside of electricity including rent, warranties, maintenance, charger communications, customer service, program reporting, network operations, taxes and business licenses, and insurance. This is in addition to development costs, including network design, site development, contracting, site surveys, engineering, utility review, permitting, construction, and interconnection. Utility ownership of additional charging infrastructure would commercially undercut the private sector, especially when solutions like more effective rate design is viable.
1.04	• This looks to have multiple recommendations in one: standardization vs. data inputs vs. rate design. Hard to answer with so much being asked. • This recommendation hits on several things. Regarding metering, we submitted a recommendation that aligns with this but I think is more actionable and based on existing research: "Design and offer various rate and metering configurations to increase participation in EV rate programs intended to increase grid flexibility and reduce grid strain." Regarding telematics, this should be allowed only if EVSE is also allowed and both categories undergo extensive measurement testing and standardization protocols. Regarding aligning TOU rates, it's not necessary across service territories, only creating a clear customer program within a service territory. • SBUA supports this policy because separate meters and submetering are significant costs, especially for small businesses. But SBUA requests clarification for why TOU periods & costs should be standardized across all IOUs & LSEs. • Vehicle data being used for settlement is not established and results in may policy concerns. A homer charger (L2) with utility-approved submetering built-in may be more optimal given a fixed location for an L2 vs vehicle. • Support. A standardized format for TOU rates does not mean the rates themselves have to be identical. • LADWP plans a pilot that would provide performance-based incentive payments for off-peak charging instead of subtractive billing. SCE is currently running a DR pilot which pays for performance using the main meter. No submeter or special hardware needed in the EVs, • IOU and POU programs in the future could take advantage of automaker date to provide VGI incentives to drivers. LADWP plans a pilot that would provide performance-based incentive payments for off-peak charging instead of subtractive billing. For commercial, separate metering combined with other policies already achieves this goal. Needs to separate out 2nd idea of common LSE rate. • LADWP plans a pilot that would provide performance-based incentive payments for off-peak charging instead of subtractive billing. • The disagreement score could be changed to agreement if there are standards, technology, and regulations in place to ensure sufficient EV submeter accuracy. Is the "standardized TOU rate format" asking only to have e.g. same summer/winter seasons, same peak, off peak periods, or is it also asking for standardized e.g. peak costs are twice as high as off peak? The former sounds doable, but the latter

	will have issues related to how different rate components are generally recovered. (SDG&E has different higher cost hours than other service territories, but keeping same structure uniform is important) • The recommended Policy Action is unclear and needs to be revised. I believe its intent is to recommend submetering as a way to avoid installation of a second utility meter to enable EV-only TOU or VGI rates. In that case, we agree this is needed and point to the submetering policy track in the DRIVE OIR. Regarding the use of vehicle telematics for submetering: metering accuracy, metering data transfer, and the mobile nature of EVs are big areas that will have to be considered in submetering policy development. • More clarification about what standardizing TOU format means would be beneficial, but the first recommendation described in the policy action is generally worth exploring • Critical need for IOU/CCA coordination here to avoid customer confusion on the same bill. Also, customers should have the ability to easily share vehicle telematics data to LSE as an opt in to virtual TOU or other forms of load shaping. • LADWP plans a pilot that would provide performance-based incentive payments for off-peak charging instead of subtractive billing. • VTA has both light duty and bus charging stations on the same meter as a facility. The cost of accessing the EV rates via a separate/submeter would take years to recoup. Hard to access VGI in this scenario. • In support of open standards. Scoring in alignment with other IOUs comments. Submetering obsolete, outpaced by Smart Meter capabilities. LADWP plans a pilot with check in the mail rebates instead of subtractive billing.
1.05	• Can we rewrite this and distill the core recommendation? This seems to bury the recommendation within the explanation • Step one is making time-varying rates aligned with grid conditions, step two is increasing participation on time-varying rates. This recommendation is trying to increase participation by harmonizing TVR but that might not match the reasoning for constructing TVR a certain way in certain customer classes. • SBUA does not agree that IOU TOU rates necessarily must be relatively consistent across different price-setting entities who could have substantially different cost structures. • For public charging, customer elasticity may not exist to defer charging to a later time. Harmonizing rates across IOUs may not reflect the real-time grid conditions in those areas or networks. • Different service territories might have different characteristics (renewable energy generation, load shapes, etc.) that lead to varying definitions of the TOU periods. • Each LSE has own cost recovery structure and are regulated through various groups. There are limits to rate harmonization • each LSE has own cost recovery structure and there are limits to rate harmonization • Each LSE has own cost recovery structure and there are limits to rate harmonization. • Perhaps though there is some recognition of different prices and different places at the grid at the wholesale (LMP) level and some signals could be given to customers to preferentially charge at the lower-cost nodes. • Ideally TOU periods would be consistent across IOUs, CCAs, direct access providers, etc. However, the CPUC does not have jurisdiction over non-IOU rates. Outside of the IOU service territories, this could probably only materialize through 1. IOU T&D tariff, and 2. policy coordination. Within each IOU specifically, the presence of different TOU periods appears to primarily be due to grandfathering. The IOUs are in the middle of a transition, and there has already been significant progress to standardize peak periods as 4-9 pm (although from a cost causation standpoint that may no longer ideal). Across IOUs, the different seasonal periods, and whether weekends have peak periods or not, would ideally be standardized. This recommendation requires significant cross-coordination with rate design to ensure that there are not unintended consequences caused by the standardization. IOUs need flexibility to adjust rates based on GRC schedules. • EV rates should reflect the characteristics of the specific IOU region. For example, on-peak times in SCE territory may not completely overlap with on-peak times in PG&E's territory, and thus harmonization across territories might not be optimal.

	• each LSE has own cost recovery structure and there are limits to rate harmonization • Consistency and predictability in rates is important to transit agencies since we have operating constraints regarding when we can charge. More likely to participate in V2G if able to. • Providing (geographically, economically, temporally) consistent price signals will advance VGI by defragmenting the market, allowing analysis and forecasting, and making something like a market price visible. Understandable target but not policy ready. How to harmonize across providers and EV drivers? Genuinely hard problem; though utilities are a lot more aligned than EVSE providers (see next row).
1.06	• Not sure what the policy recommendation is. • I'm not sure what this recommendation is getting at. • SBUA believes this needs further explanation and EVSE supplier input on whether they agree with this policy. • Price signal to the EVSE should reflect system costs but EVSE operators should be allowed to manage their electricity costs separately from their pricing strategy. Site level congestion peaks may not align with system level peaks and therefore pricing to EVSEs should not be expected to move in lockstep with pricing to EVs. • Many factors go into end-user pricing, including site congestion and the ability for energy storage to arbitrage versus compromising user experience. • This would seem to disincentivize the integration of storage with EVSE. If a DCFC operator wishes to install storage to take advantage of TOU pricing, and offer a flat rate to EVs, that should be allowed. Rather than requiring the EV to also face a TOU rate when using the EVSE. • This would require changing the deregulation of charging networks • would require changing the deregulation of charging networks; We might be misunderstanding this one • Rates charged by third- party operators are currently not regulated products. • The Commission should promote alignment of price signals to EVs with those that are seen by EVSE. From the perspective of IOU programs, we agree with this recommendation. For EVSEs installed outside of IOU programs, the CPUC does not have jurisdiction to mandate the price the end user sees. • More clarification is needed on the problem statement that this recommendation is trying to solve. Specifically, in what scenarios are drivers being passed two different price signals, one by the EV and EVSE, when charging at a single location? • TOU prices signals should be passed through to drivers by default to realize the grid benefits and fuel cost savings that justify the investment of customer funds • would require changing the deregulation of charging networks • Don't really understand this policy recommendation. • This item is recommended by general ratemaking principles of cost reflection, understandability, equity, and long-term sustainability. A minimal level of consistency is essential for the system to work at all. But more than that is probably required. As these charging and discharging transactions become more common and more convenient, the ability of small participants to act as buyer or seller at different times and locations in the grid make the system more like a wholesale market, where arbitrage or just mispricing of very similar products can cause supply and demand to tip out of balance. A high level of consistency is needed to insure against this, and to allow needed cost benefit analysis to give consistent and understandable results.
1.07	• Generally, seems useful. I am not aware of which CA IOUs might have something to this or not, or any pilots on this. • A more dynamic rate structure for EV fleets would allow for more cost-effective and affordable EV fleet deployment. • Demand charges are a threat to VGI, and any demand charge mitigation approach should extent to public charging as well and not just fleets. • This would vary drastically based on the type of fleet - i.e. large school buses with big batteries, vs. municipal light-duty fleets, vs. delivery van fleets. Unsure of the rate that is best for all types of fleets…probably not one standard rate. • Commercial EV rates have already been approved for two of the three IOUs, so less critical.

	• commercial EV rates have been approved for two of the three IOUs, so less critical • Commercial EV rates applicable to EV fleets have already been approved for two IOUs, so immediate policy change is not needed. • Language should be clarified to avoid confusion with current commercial EV rate efforts. • Would like to clarify whether such dynamic demand charge alternatives would apply to all commercial EV charging and not just fleet charging, and how these options would dovetail with IOUs' commercial EV charging rates that have been recently adopted or are currently under consideration. • Most IOUs have approved or proposed commercial EV rates at this point, with requirements to development optional dynamic rates in addition. • Separately metered (or sub metered) stations might not be possible for smaller fleet facilities, making them not eligible for PG&E BEV rate, so there needs to be multiple options for EV fleet rates instead of just one. • commercial EV rates have been approved for two of the three IOUs, so less critical • Instead of rates for specific rates, all commercial use cases (fleet, public DCFC, large L2s) should be able to access rates. • Although there are existing "EV Fleet", a more dynamic rate structure with average daily demand charges instead of max demand charges for the month would potentially be beneficial. • We have already created EV commercial rates. For that reason, it is not a priority.
1.08	• This needs more framing. • TOU peak often needs to be 3-4 times greater than off-peak rate to effect desired charging during off-peak period. • Public charging customers may not have ability to adjust usage and higher differentials may impede EV adoption and SB350 goals • A high differential between peak and off-peak periods provides a strong signal to EV drivers to encourage off-peak charging where possible. As long as such as rate is option, so that fleets who do not have such flexibility can choose to not adopt it. • Most utilities have already done this, therefore it's less critical. • most utilities have done this, so less critical • Most utilities already have significant differential between peak and off-peak EV rates (e.g. SDG&E EV-TOU-2 and EV-TOU5). • Rates should also ensure they follow cost causation principles, and provide a contribution to margin (CTM). There must be a balance between cost recovery & ensuring affordable rates for all customers and incenting off peak charging for EV drivers. • Not as relevant as CCAs are only relevant to customers for generation rates • most utilities have done this, so less critical • Dynamic rates should be optional and are unlikely to be taken up this early in EV market. • Differentials between peak and off-peak rates help incentivize charging at times that are beneficial to the grid.
1.09	• This recommendation is not written in a way that makes it clear what the ask is- is that current utility tariffs don't allow customers w/ on-site solar and/or solar to go onto the rate? Is that there isn't a way for the value to realized? It's just unclear what this is solving. • Answer to CPUC questions would help clarify. • Already the case as storage is classified as generation to Electrify America's knowledge, as long as the charging and storage is metered separately from other host facility load • Support, but we note that the power demand for transit EVSE is probably much higher than what on-site solar can provide. • support in theory but many details to be worked out • Support in theory but many details to be worked out. • We do not take a position at this time whether solar should be allowed on commercial EV rates, but agrees that the policy should be consistent across IOUs. • Commercial EV rates should be allowed to include RE and battery storage on the same meter • support in theory but many details to be worked out

	• VTA and other transit agencies either have solar or are looking at integrating solar and battery storage to lower charging costs so allowing on-site solar and/or storage to utilize commercial EV rates is important if it is not currently allowed by utility tariffs.
1.10	• I'm not sure what this recommendation is getting at. • SBUA agrees with this policy to help flatten Duck Curve. • Support. Drivers need more information and education and outreach on the rates. • The key to scaling VGI is large scale adoption of time variant rates (both traditional TOU and dynamic rates) • The key to scaling VGI is large scale adoption of time variant rates (both traditional TOU and dynamic rates) • The key to scaling VGI is large scale adoption of time-variant rates (both traditional TOU and dynamic rates). • Need to clarify if "high levels of participation" refers to kWh utilization. Such rates would probably require a fixed charge and low volumetric charges, and/or very high differentiation between peak and off-peak rate. If so, volumetric charges need to be designed such that the rate still provides a positive contribution to margin (CTM). Need to clarify if having the rate be better for EVs "in almost all cases" refers to recommending EV rates that do not recover full equal percentage of marginal cost (EPMC)-scaled costs (which we may be opposed to). • Not sure what is meant by a TOU rate that's "designed" or "better for EVs" in a whole house sense. E.g., if you increase the differential for off-peak periods by shifting more cost recovery into peak times, this could penalize customers on whole house TOU rates. More clarity needed. • The key to scaling VGI is large scale adoption of time variant rates (both traditional TOU and dynamic rates) • We have already created TOU designed for EVs. For that reason, it is not a priority.
1.11	• DR is important but that isn't a rate per se, so this needs to be rewritten or clarified. • SBUA believes this is critical for flattening Duck Curve. • Control signals for public charging may impediment EV adoption and SB350 goals; May be suitable for home charging • It may be more advantageous for utilities to provide signals to third parties that aggregate EV charging load in such a way that provides no adverse impact on EV drivers. • To simplify this should apply to all DERs and not just EVs. • Likely to be open to all DERs • Likely to be open to all DERs. • We support real-time price rates as long as they are 1. optional, and 2. reflect equal percentage of marginal cost (EPMC)-scaled costs (we may conditionally support real-time rates that recover non fully-scaled costs on a case by case basis). This recommendation needs more specifics of what are the priority aspects to standardize amongst the IOU real time rate design. Also is this recommendation proposing that the guide be developed by a sub working group? • Agree with the "rate design" piece for RTP and event signal rate options; not sure what is meant by a standard implementation guide. Similar to 1.13 and 1.18 • Likely to be open to all DERs • Can be useful as a concept in the longer dwell time locations and residential use case. Better to be wrapped up in other policy cases than on its own. • There is a huge range of possibilities between merely informational signals to control to transactional signals
1.12	• Supportive of options and alternatives, but characterization of submetering as a challenge or in need of re-examination is problematic - some may see submetering as viable • EVSE submetering is low-cost and meets HB44 accuracy requirements. For EV rate purposes, EVSE submetering is a valuable solution and does not need AMI. In fact, AMI integration with EV charging is not at all straightforward. For other DER integration, AMI may be useful. • As we wrote in response to 1.04, the more metering configurations accommodated, the better. It's as simple as that.

	• SBUA concludes this is probably cost effective, and should help flatten Duck Curve and reduce GHGs. • Humans have a different level of price elasticity compared to a vehicle or home EVSE that can respond to more granular rates if financially incentivized to do so • The key to scaling VGI is large scale adoption of time variant rates (both traditional TOU and dynamic rates) • The key to scaling VGI is large scale adoption of time variant rates (both traditional TOU and dynamic rates) • SDG&E recommends assessing the cost-effectiveness and existing market demand of PEV submetering for retail billing compared to the alternative approaches such as whole house time variant rates that may capture similar benefits. The IOUs are currently engaging with the CPUC and other stakeholders to develop a PEV submetering protocol as part of the DRIVE OIR. • Should not preclude EV-only rate options • What is the paradigm that needs to be reexamined? Is it that we are very focused on submetering, but it perhaps is not necessary? Is the "re-examination" just that the CPUC should acknowledge that, or is this proposing some time of study, working group, etc. for the CPUC to reassess the viability of using whole house vs. submetering? • While CA is moving to default TOU rates for residential customers on a whole-home basis, EVSE submetering policies and technical solutions are still needed to maximize customer choice and fuel cost savings, and also enable higher-order VGI use cases. For instance, whole house TOU will not be a cost-effective solution for all customers, especially those with inelastic energy demand, high AC consumption, non-flexible work schedules, etc. These customers should still have the option of accessing TOU rates for EV charging. Other relevant use cases for EV submetering include: TOU billing for MUD customers behind a master meter; enabling EV-only dynamic rates; and baselining and settlement of EV load separate from the whole home for utility and CAISO facing grid services. • significant efforts have gone into submetering of EVs. While unsuccessful in CA they have managed to successfully implement this in other states (e.g. Minnesota Xcel Energy). To enable submetering instead of looking at other alternatives, utilities should take lessons learned from pilot and implement them. IOUS should agree on a common data format and communication protocol for billing, soften metering to cater to specific service (you don't need 1-minute resolution for an hourly dynamic rate) and have clear metering standards and testing protocols for 3rd party metering /submeter to validate for qualification. Submetering is important and vital but already significant work has been done by industry (non-utility). IOUs should work on the above mentioned and implement quickly. • The key to scaling VGI is large scale adoption of time variant rates (both traditional TOU and dynamic rates) • Not sure if there is a rate that would be beneficial to electric buses and transit facilities. • We recommend assessing the cost-effectiveness and existing market demand of PEV submetering for retail billing compared to the alternative approaches such as whole house time variant rates that may capture similar benefits. We, along with SCE and SDG&E, is currently engaging with the CPUC and other stakeholders to develop a PEV submetering protocol as part of the DRIVE OIR.
1.13	• This seems like a policy principle for all DERs • This was a good effort on consolidation. • Critical to have time- and location-specific price signals to achieve GHG reduction goals and optimal grid function. • Many factors go into end-user pricing, including site congestion and the ability for energy storage to arbitrage versus compromising user experience. Causing sticker shock at a retail charging level will impede EV adoption and SB350 goals. • Generally agree • Mid-term is adaption feasible but not short-term (i.e. > 2023) • mid-term is feasible but not short-term • More complex rate options are feasible in medium-term. • Must ensure competitive / market forces remain.

	• We agree with this recommendation in principle, but may differ with the recommender on how this recommendation is acted upon, i.e. how rates are designed to capture "realistic" costs. For example, distribution costs vary more closely with demand than with system-wide TOU pricing signals, so some demand-based charges can be justified. • Enel X believes development of optional, technology-agnostic dynamic rates across all three IOU territories should be a priority for the CPUC following conclusion of the WG, as it provides a relatively straightforward method to promote grid integrated charging in a way that reflects many of the benefit streams or applications that have been discussed in the VGI Valuation Framework. • mid-term is feasible but not short-term • Already exists with existing commercial rates. Beyond this, anything proposed should ensure that retail EV charging rates still accommodate the costs of networking and maintaining EVSE. Potential to undercut private sector, hindering deployment of additional infrastructure. • Retail EV charging rates should be based on the costs of providing service to the transportation customer class which has distinct characteristics compared to the C&I customer class. • A minimal level of consistency is essential for the system to work at all. But more than that is probably required. As these charging and discharging transactions become more common and more convenient, the ability of small participants to act as buyer or seller at different times and locations in the grid make the system more like a wholesale market, where arbitrage or just mispricing of very similar products can cause supply and demand to tip out of balance. A high level of consistency is needed to insure against this, and to allow needed cost benefit analysis to give consistent and understandable results.
1.15	• Supportive but unclear of viability - Can rate designs be approved quickly, when they require extensive GRC or GRC-like processes? • It would be helpful if additional context was provided- are the applications/proposals currently not approved promptly? Is there a structural reason why and that should be the policy recommendation? • Time-varying (and ultimately location-varying) rates for EVs should be implemented ASAP to avoid grid instability and to send appropriate price signals for flattening Duck Curve. • EV rates for residential and commercial customers are critical for supporting EV infrastructure deployment. • Not well-defined recommendation. Rate case litigation and discovery due process exists for a reason. • Support. The utility proposal should include funding for education and outreach on the rates to drivers. • Any adopted process must still allow record to be built and provide adequate time for parties to provide input. Furthermore, the CPUC should prioritize some EV rates over others based on need and demand. Is this recommendation also proposing a change in the process to approve time-varying EV rates (e.g. using a Tier 3 Advice Letter process instead), or just that the CPUC should prioritize the Proposed Decisions of EV rates over other proceedings? What is action for the CPUC from this recommendation? • Unclear what the problem statement is here. • CCAs are not required to get CPUC approval for rate changes, making CCAs a potential fast track approach to experimenting with TOU rates as long as they aren't confusing to customers in a shared bill environment. • The VGI report and working group should not create new, EV-specific rate design recommendations that are outside or inconsistent with what the utilities and CPUC already are doing in other generic rate design proceedings.
1.16	• This could be one path to getting credits but unclear if this is optimal or best path - see CESA's informal comments • Eventually this credit will need to be identified, and I agree that the timeframe should not be this year or next. Recommendation 1.16 can be a subcategory of 1.14, or at least something to consider when addressing 1.14. • Disagree because of the "full retail rate" provision in the response by VGIC to PUC comments. This has been a contentious topic of disagreement in the past, and it might compromise the ability to reach consensus and make progress on V2G among all involved parties.

	• In order to flatten the Duck Curve and achieve GHG reduction goals, NEM credit for V2G exports is critical, and CPUC should resolve this with Battery Net Metering policy, while not giving credit for electricity downloaded from grid for on-site storage. • In concept, V2G can provide a lot of benefit to grid stability, resiliency, etc. But policymakers need to focus on other pressing TE needs (i.e. education/outreach and EVSE installation) vs. getting caught up on V2G credits right now. • This is relevant to rule 21 proceeding. Need to be implemented to protect ratepayers and security • relevant to rule 21 proceeding. Need to be implemented to protect ratepayers and security • As implemented should protect ratepayers and address metering and settlement issues. • The disagreement score could be changed to agreement if the issue of cost-shift created by the current NEM tariffs is addressed. Until then, we do not support NEM for V2G. • Similar to 1.14 • This should be carefully examined to negative impacts on utility customers, as NEM is already a significant cost shift putting upward pressure on rates for other customers • CCAs can also implement this for customers • relevant to rule 21 proceeding. Need to be implemented to protect ratepayers and security • CPUC is in process of reforming NEM tariff. Expanding NEM tariff will create a hidden subsidy and shift costs to customers who are unlikely to be able to take advantage of this program
1.17	• This is more specific to school buses but unclear on what the tariff is seeking to achieve • This could be reoriented to be not technology-specific, but customer-specific, e.g. schools. • Not clear what type of tariffs exactly, and why or how those tariffs would be unique to School Buses specifically • SBUA believes this is an important component of V2G rates which are time-variant and location-variant. • Better to focus on deployment of school buses now than get caught up in the V2G credit value. • This is relevant to rule 21 proceeding. Need to be implemented to protect ratepayers and security • relevant to rule 21 proceeding. Need to be implemented to protect ratepayers and security • School Bus V2G currently being trialed in SDG&E Pilot. • There does not need to be a specific EV school bus rate (i.e. only school buses and maybe an additional small subset of customers). A dynamic rate could prioritize attractiveness to school buses, but all or most V2G use cases should be eligible. • Not in favor of a rate or tariff that is specific to a single vehicle class. Also, need to define what benefits or applications the tariff would aim to capture to better ID what the policy solution would be (e.g., NEM or RA credits for exports) • Worth exploring • Disagree with sector-specific carve-outs in general • relevant to rule 21 proceeding. Need to be implemented to protect ratepayers and security • Should these tariffs be specific to electric school buses or all V2G applications? • This item raises concerns based on general ratemaking principles of cost reflection, understandability, equity, and long-term sustainability. Rates should generally not be tailored for highly specific use cases. Where rates don't reflect underlying cost in a straightforward way, they are difficult to justify, difficult to track from a cost-benefit perspective, and threaten to be unsustainable in the long run depending on customer use pattern. Where subsidies or discounts to support particular charge or discharge modes are necessary, they should be explicit rather than codified into a separate rate
1.18	• Sounds like a solid policy recommendation. • Is there a downside to making the EV charging tariffs more complex for customers to understand? Will this add confusion for customers on how to best charge their EVs? • SBUA believes this is a solid transition step towards real-time dynamic pricing which varies with both time and location. • As long as the tariffs are voluntary this could potentially work for some L2 charging use cases, but critical peak pricing is not the right incentive mechanism for DC fast charging in the public station setting.

	• CPP pricing may cause sticker shock and inhibit EV adoption and SB350 goals. Rewards or rebates are a better approach, and incentivize use of storage if available during such times without causing sticker shock. • While we do not anticipate uptake of such a program by a high percentage of EV drivers, there could be enough who are interested to make a significant difference during critical peak events. • SDG&E proposed EV-HP rate includes optional CPP commodity rate for bundled customers. • Similar to 1.11 • Not sure transit fleets would easily be able to participate in these events. • This is a DR rate that would be technology specific; the CPUC's current guidance is to be technology neutral. Additionally, we do have rates for non-res customers. How would this add value beyond the EV rates and DR programs available for EVs today in our service territory?
1.19	• As written, it doesn't seem actionable without specifics • This isn't a recommendation in and of itself, but it is critically important as a framework. Recommendation 2.07 falls within a PBR framework. Our organization has done a lot of work on this topic: https://energyinnovation.org/what-we-do/power-sector-transformation/ratemaking-and-utility-business-models/ • Much clarification needed, including how op-ex would be added to ROR calculation commensurate with the risk taken in making additional expenditures for EV infrastructure. Would apply only to IOUs: CCAs are not under CPUC regulation. • Very complex subject - would need coordination between LSEs to ensure metering technology has similar capabilities. • Very complex subject • Very complex subject • We do not support performance-based ratemaking. If there is any development of PBR, it needs to be carefully vetted to ensure that there is a method to verify the accuracy of the reported metrics, a review process to develop the incentive, and that the metrics are resistant to being gamed. Otherwise, we do not support performance-based ratemaking. • Better definition needed on the overall objective for a PBR scheme. Keeping costs low? GHG reductions? Encouraging / enabling third party competition? • Very complex subject
1.20	• This could be an "umbrella" policy, and recommendations like 1.07 can be included within it. • Not clear what type of tariffs exactly, and why or how those tariffs would be unique to School Buses specifically. • MHD tariffs needed to provide accurate price signals reflecting time- and location-specific costs to grid. • PG&E and SCE have already implemented commercial EV rates and SDG&E is working on their own. Whether or not these commercial EV rates are sufficient for MHD and all fleets is yet to be seen. • High-Power charging rates already in effect for most of California. Medium/Heavy duty part of same scope and reduction of demand charges critical • Two IOUs have commercial EV rates and the other IOU's proposal is being considered, so this isn't critical. • 2 IOUs have commercial EV rates and the other IOU's proposal is being considered, so not critical • Two IOUs have commercial EV rates and the other IOU's proposal is being considered, so not critical. • This needs clarification of how such tariffs need to be different from currently proposed or implement commercial EV rates. The success metric also needs to be more specific (e.g. by quantifying # of customers participating in V2G, GHG reductions, etc.) • Typically not in favor of rates or tariffs that are specific to vehicle classes. Agree though that super high-capacity MD/HD fleet charging might entail new rate design or cost allocation considerations that are not at all comparable to other types of commercial loads, and that EV charging rates should be developed with those differences in mind • See answer to use case 1.07 • Disagree with sector-specific carve-outs • 2 IOUs have commercial EV rates and the other IOU's proposal is being considered, so not critical

	• There are specific tariffs for medium/heavy duty vehicles but not for light duty fleets. This might be beneficial. Dynamic rates don't work for fleets, in general. May work in limited applications, many fleets don't have ability to switch charging outside of a few hour window... b/c of the ratio of battery size/ vehicle and the dwell time is much lower than LDVs • We have created EV commercial rates. This recommendation is not applicable to us for future strategy and for the integration of VGI.
2.01	• This may be a medium-term recommendation related to DERMS and DSO business models - applicable to all DERs (we all want this!) • This recommendation needs a bit more context. It sounds like a DR recommendation but needs more framing to determine what the real suggestion is. • How would that be different that the current setup of utility DR programs, like CBP? Do all DERs receive the same signal (i.e. the signal is technology agnostic)? Or the signal would be specific for EVs? • Viable concept, but needs explanation on how to implement. • Wholesale LMP rates may achieve same objective if passed onto allow behind-the-meter storage to optimize charging or export. • Enel X supports exploring and implementing Distribution System Operator, transactive energy, or P2P energy trading concepts. An incremental improvement over the status quo would be to implement optional dynamic rate schedules that push granular price signals to influence end user charging behavior based on actual grid conditions, GHG signals, etc. • Is this saying that EVs should be considered DERs in a wider market place and given equal footing with other DERs? If so, yes Strongly Agree, but not sure if this is the intent • This recommendation may advance VGI in California. EV owners, and vendors of EV aggregations, are both likely to be more sensitive to arbitrage opportunities (both economic and environmental) because of the flexibility of the under-utilized charging resource (and to a lesser extent, the potentially under-utilized discharge resource) than most other categories of demand or storage, which may be either less flexible or must in general be operated closer to high utilization of capacity to be economic.
2.02	• It depends on what is incrementally funded and whether TE programs are insufficient - see CESA's informal comments • I'm not sure I agree with the timeframe on this, as most EVs as storage uses are farther out, but I agree that eventually EVs should be used as storage and if so, be able to receive the value they're receiving. • Just note this is very different than SGIP for co-located stationary storage with EV chargers. • SBUA requests further clarification of how SGIP incentives would be structured to effectuate optimal V2G implementation. • V2G technology is still mostly in development and seems like funds would be better spent on pilot programs until it is ready to commercially scale more broadly. • In concept, V2G can provide a lot of benefit to grid stability, resiliency, etc. • This overlaps with other SGIP policy proposal. • overlaps with other SGIP policy proposal • Consider whether receiving SGIP should obligate customer to participate in programs. Should protect ratepayers and address metering and settlement issues. • More details are needed to determine whether we support, but cost-effectiveness should be evaluated and program must be designed to prevent cost-shifting. • Broad agreement that there may be a way to incentivize/subsidize the batteries inside V2G EVs in return for some specified ongoing behaviors, not sure SGIP framework is entirely appropriate though • overlaps with other SGIP policy proposal • Inappropriate to fund EVs from SGIP. SGIP is established by legislature for specific technologies and specific purposes. VGI OIR is inappropriate forum to consider changes to SGIP program.
2.03	• The time of usage of EVSE is partly dependent on where the EVSE is sited, e.g. residential or workplace. Also partly based on price signals, ideally. Is this saying there should be rebates based on where it's expected there will reliably be midday load? If so, I think this will essentially become a workplace charging incentive. But "reverse EE" makes it sound more like a DR type incentive? More clarity needed.

	• How is this different that load shifting? Load shifting, by design, provides incentive for the combined actions of (a) reducing load a during specific time period and (b) increasing load during another time period. If, per this recommendation, one incentive is provided for action (b) (load increase), and a separate incentive for action (a) (load curtailment in existing DR), wouldn't that risk double-counting? • Isn't "reverse EE" value/benefit already imbedded in the cheap energy price in the middle of the day? • Need further clarification of how P4P would be structured optimally, and whether EE funds could be allocated if IDSM benefits achieved. • Establishing baselines by creating charging headaches may impede SB350 and EV adoption goals. • With excess solar power in the middle of the day (particularly late morning and early afternoon), encouraging EV charging at this time would reduce solar curtailment and lead to emission reductions. • Support pushing load at workplaces to midday. While SCE is currently doing this in their Charge Ready Demand Response Pilot, more demonstrations are needed to see if rebates or TOU rates are best. TOU rates are likely lower cost. 2.03 fits better under #7 • Support pushing load at workplaces to midday. More demonstrations are needed to see if rebates or TOU rates are best. TOU rates are likely lower cost. 2.03 fits better under #7 • Support pushing load at workplaces to midday. More demonstrations are needed to see if rebates or TOU rates are best. TOU rates are likely lower cost. 2.03 fits better under #7 • More details are needed to determine support, but cost-effectiveness should be evaluated and program must be designed to prevent cost-shifting. • While we believe that such "reverse EE" incentives could be developed and implemented to support EVSE deployment in the near-term, we believe there is a greater conversation to be had about flipping the typical script for EE programs based on avoided costs through permanent / bona fide load reduction, and looking to develop comparable yet inverse "beneficial electrification" programs that avoids costs and GHGs by maximizing renewable energy uptake, or increases utilization of the existing distribution system, on a permanent basis. • Needs to be proven, unclear how charging behavior is factored in or which market segments this is relevant or • Addresses one aspect of the project of getting EVs charging when the sun is up, but should be contextualized and combined with other incentives • Support pushing load at workplaces to midday. More demonstrations are needed to see if rebates or TOU rates are best. TOU rates are likely lower cost. 2.03 fits better under #7 • The recommendation focuses on load growth, which is counter to current state policy which defines energy efficiency as load reduction. Therefore, this is not an energy efficiency recommendation. • This proposal also seems to run afoul of broader state mandates to reduce energy usage and increase energy efficiency. • Rather than concentrating on simply building load in the middle of the day, this approach should look at shifting energy usage from times when wholesale energy prices and GHG emissions are high to times when energy prices and GHG emissions are low. • This approach of load shifting is more in-line with a "shape" DR program. • An alternative to a shape DR program would be a dynamic or real-time TOU rate, though any rate designs should be considered as part of the broader rate design initiative. • It is not reasonable to limit this offering to VGI, and this option should be available to any customer technology.
2.04	• Generally, load balancing/management should be encouraged to reduce overall cost. National Electrical Code (and I believe California Electric Code) allows for energy management systems, not sure what CA restricts that this is getting at. Or perhaps it's suggesting how it be more encouraged? • Need to tackle the specifics, including the concept of "performance guarantee". • SBUA recommends clarification on how BTM load balancing option could be implemented. • This is done today if the customer wants it. No policy change needed. Customers get to manage their own load and choose low KW. More education and simple solutions are needed (e.g. use a safety breaker)

	• This is done today if the customer wants it. No policy change needed. Customers get to manage their own load and choose low KW. More education is needed (e.g. use a safety breaker) • This is done today if the customer wants it. No policy change needed. Customers get to manage their own load and choose low KW. More education is needed (e.g. use a safety breaker). • There were issues in the Rule 21 WG over whether the IOUs could rely on the solar providers to not produce over a stated capacity. Need to see if those issues have been resolved. Whether this recommendation is viable or not would likely predicate on that. • Critical near-term action the CPUC can explore as part of this WG and the TEF to promote customer choice and competition and ensure the lowest-cost integration of EV charging load • Residential BTM load balancing is also critical for renewables alignment for CCAs. Avoiding upgrades is a critical goal that can also be achieved through EVSE energy management and level 1 charging. • This recommendation was consolidated into recommendation 2.17 • This is done today if the customer wants it. No policy change needed. Customers get to manage their own load and choose low KW. More education is needed (e.g. use a safety breaker) • Ability to avoid primary or secondary upgrades would be very beneficial to transit agencies. • This is done today if the customer wants it. No policy change needed. Customers get to manage their own load and choose low KW. More education is needed (e.g. use a safety breaker)
2.05	• Managed charging should be an option, incentivized, and encouraged, but not required • VGI cannot be easily done with managed charging capability. • Agree with Policy Action as stated in column F, but do not agree with comment in column G (What success looks like). Achieving managed charging capability does not necessarily require smart/connected charging infrastructure (vehicle telematics). • SBUA requests further details and clarification on benefits and costs of managed charging. • Requiring managed charging can add unnecessary costs and complexities that can reduce the total number of chargers deployed for any given program. "Managed charging" is loosely defined and can mean different things to different people. "Networked charging capability" may be a better term. • Public charging customers may not have ability to adjust usage and higher differentials may impede EV adoption and SB350 goals • Managed charging capability carries additional up-front capital costs and ongoing costs such as network fees or bandwidth usage. It is not clearly demonstrated that the value of managed charging exceeds the incremental cost of such capability in all cases. • If the value of managed charging exceeds its costs in specific cases, then such value should be offered to the EVSE owner if they choose to install and employ of such capabilities. If its value does not exceed its costs, it would be economically irresponsible to mandate it. • This is done today for light duty vehicle pilots as an established market. The adoption of this requirement may hinder an emerging market and its growth such as medium and heavy-duty sector. • This is done today in for light duty vehicle pilots as an established market. The adoption of this requirement may hinder emerging market growth such as medium and heavy duty. • This is done today in for light duty vehicle pilots as an established market. The adoption of this requirement may hinder emerging market growth such as medium and heavy-duty. • Managed charging capabilities should not be limited to EVSE-centric solutions and technology requirements. There are other solutions. • Agree in principle, implementation however can take many forms. Many of the CPUC's program currently require the site host to have a load management plan. However, this has not necessarily translated to sites participating in demand response events (as brought up by Noel Crisostomo of the CEC in one of SCE's PAC meetings). Is this recommendation only envisioning charging customers time-variant rates, or does it also require DR participation? The former would probably have more customer buy-in, but may also run into issues with EVSP pricing and with site hosts who want more of a "set and forget" approach to their EVSEs. • Agree that this is needed but unclear if it's in scope for this WG, seeing as HW requirements were covered in the last VGI WG which has been deemed out of scope. Similar to 2.06. • Is this addressed in SB676?

	• This is done today in for light duty vehicle pilots as an established market. The adoption of this requirement may hinder emerging market growth such as medium and heavy duty. • Theoretically useful and valuable in longer dwell time use cases, but not for short commercial dwell time use cases. Customer experience with public fast charging would be severely diminished. • This is done today in for light duty vehicle pilots as an established market. The adoption of this requirement may hinder emerging market growth such as medium and heavy duty.
2.06	• VGI cannot be easily done with managed charging capability, so taxpayer/ratepayer money shouldn't be spent on equipment that isn't future-proofed. • What does "smart" entail? What is the list of criteria to qualify charging infrastructure as "smart"? • Achieving managed charging capability does not necessarily require smart/connected charging infrastructure (vehicle telematics). Any managed charging through infrastructure MUST take into account customer travel needs and/or EV energy considerations. • Needs further definition of what smart functionality would include. • Requiring smart charging functionality can add unnecessary costs and complexities that can reduce the total number of chargers deployed for any given funding source. "Smart functionality" is loosely defined and can mean different things to different people. "Networked charging capability" may be a better term. • Public charging customers may not have ability to adjust usage and higher differentials may impede EV adoption and SB350 goals • Smart functionality carries additional up-front capital costs and ongoing costs such as network fees or bandwidth usage. It is not clearly demonstrated that the value of smart charging exceeds the incremental cost of such capability in all cases. • If the value of smart charging exceeds its costs in specific cases, then such value should be offered to the EVSE owner if they choose to install and employ of such capabilities. If its value does not exceed its costs, it would be economically irresponsible to mandate it. • Several markets such as off-road charging is better served for VGI using indirect means such as TOU rates. This action needs more clarification to carve out appropriate market segments • Several markets such as off-road charging equipment is better served for VGI using indirect means such as TOU rates. This action needs more clarification to carve out appropriate market segments • Several markets such as off-road charging equipment is better served for VGI using indirect means such as TOU rates. This action needs more clarification to carve out appropriate market segments. • "Smart functionality" needs to be defined. The CPUC programs currently generally requires EVSEs to be networked. Is this also recommending that all the EVSEs also be e.g. bidirectional? • Agree, but as written this isn't a policy action for the CPUC. Similar to 2.05 • Government should be cautious of the potential chilling effect continuous introduction of new requirements can have on EVSE industry • Several markets such as off-road charging equipment is better served for VGI using indirect means such as TOU rates. This action needs more clarification to carve out appropriate market segments • Use case in the short term to be for long dwell use cases and fleets. Increased cost of infrastructure and complexity for the driver would be a large barrier in public fast charging sphere • the problem is the state isn't currently funding much charging infrastructure outside of Cal-EVIP for LDVs…do we mean when they are providing any incentive? Or paying the full cost? • Managed charging capabilities ensures that EV charging can be managed in a way to minimize adverse impacts to the grid. Note that this capability will future proof the infrastructure to ensure this capability is available when grid constraints arise.
2.07	• This is a concept but it isn't policy ready in the sense that the PIM framework needs to be constructed, and then EVs meaningfully included. Overall this helps VGI fit into reliability and climate goals. • Doesn't that exist today? Through existing and piloted DR programs? • SBUA requests further details needed regarding structure and function of DR performance incentive. • Baselines are an issue for any demand response for charging; whether residential or public • Clarification is required on wholesale verses proxy DR services and the inclusion of LSE which aren't governed by the commission. More likely mid-term effort (i.e. > 2023)

	• Clarification on wholesale verses proxy DR services and inclusion of LSE which aren't governed by the commission; More likely mid-term • Clarification on wholesale verses proxy DR services and inclusion of LSE which aren't governed by the Commission; more likely mid-term. • We concur that the questions raised in the CPUC's comments need to be clarified. • Similar to 1.19 on PBR. Unclear how this fits into existing DR programs or other performance incentives for EE or DR • as long as the demand reduction is coincidental to system peak demand. Would this be an incentive outside normal rates? • Similar to 1.18? • Clarification on wholesale verses proxy DR services and inclusion of LSE which aren't governed by the commission; More likely mid-term • Demand reduction technologies should extend only to residential, workplace, and fleet use cases. • Demand response today allows for EVSE participation today. We recommend improving current DR programs today. For example, the CPUC could adopt EVSE baselines (as approved by CAISO). More likely midterm.
2.08	• This could tie into microgrids tariffs or development that enable multi-DER resiliency solutions • PSPS resilience is one of the near-term use cases for V2X but that's only possible if people have the necessary equipment. • Would be good to delve into the specifics • would emphasis V2GX component • CCAs generally favor independence from CPUC and IOU influence, and have different cost and management structures which may cause them to favor different strategies for enhancing resilience. • Coordination is required across LSE efforts, standards and title development, market messaging, etc. Cost recovery issues to be worked out. • Coordination is required across LSE efforts, standards and title development efforts, market messaging, etc. Cost recovery issues to be worked out. • Coordination is required across LSE efforts, standards and title development efforts, market messaging, etc. Cost recovery issues to be worked out. • We support the general recommendation that there needs to be consideration of resiliency for EVs. Exact implementation details of this recommendation need to be fleshed out, such as any changes needed based on Energy Division's resiliency proposals in the Draft TEF. • Policy frameworks and incentives for back-up gen and resilience for PSPS events are certainly important and are being pursued at the CPUC through the microgrid and SGIP proceedings. Not sure how important it is for IOUs and CCAs to offer coordinated incentives though. • Coordination is required across LSE efforts, standards and title development efforts, market messaging, etc. Cost recovery issues to be worked out. • Resiliency and backup power in case of a grid outage is a major concern of public transit agencies. • Needs coordination and more details on how it would be implemented and how it aligns with other policies.
2.09	• School buses are a near-term V2X possibility, so existing and potential pilots should be leveraged. • Need more details on what is meant by school bus charging solutions. • Needs to be coordinated with CARB, CEC and other agencies • needs to coordinated with CARB, CEC and other agencies • Needs to coordinated with CARB, CEC and other agencies. • Are there any additional steps that need to be taken for this proposal, besides what is being considered in the draft TEF? • The answer here might just be "EPIC" • Already programs for this • needs to coordinated with CARB, CEC and other agencies • A Rocky Mountain Institute December 2019 report "Reducing EV Charging Infrastructure Costs" (https://rmi.org/insight/reducing-ev-charging-infrastructure-costs/) has determined that soft costs are

	a significant bottleneck for deployment. We would need some more clarification details on the recommendation for utilities to establish dedicated School Bus charging programs and VGI roadmap for School Bus charging.
2.11	• Seems like a solid proposal. I think it might be most successful as almost like a midstream incentive (incenting dealers to sell EVs), but it couldn't hurt by adding VGI capability. • We agree on the principle that automakers, dealers, and utilities should be collaborating on VGI programs. However, the transactional flow specified in this recommendation needs further investigation. For example, why should the incentive go to the dealer as opposed to the driver directly? Is there evidence of improved performance? • Many dealerships are currently not very knowledgeable about EVs and VGI, and may receive higher incentive for ICE vehicles. • Pre-programmed L2 at sale may increase residential VGI adoption significantly • Dealerships already face challenges in communicating to EV buyers the options such as TOU. More intricate VGI options may be outside the skill-set of a typical EV dealership. • Should not be a requirement, but it's OK as a "finders fee" incentive. Would need demonstrations on these different ideas • Should not be a requirement, but OK as a "finders fee" incentive. Would need demos on these different ideas • Should not be a requirement, but OK as a "finders fee" incentive. Would need demos on these different ideas. • SDG&E faced significant issues in enrolling customers on TOU rates, let alone VGI functionality, in its Dealership Incentive Program. The CPUC concluded from the program that dealership incentives are not an effective way to encourage EV adoption and time-variant charging. While we do not take a position of whether it agrees with the CPUC's conclusion at this time, this recommendation needs to provide significant detail of how new dealership incentives for VGI could be redesigned to overcome the challenges posed in SDG&E's Dealership Incentive. • Not directly relevant to Enel X as an EVSP unless we partner with OEMs / dealers to help achieve these outcomes, but we support the approach. • This should be an upstream policy recommendation for the OEMs, not dealers. Dealership managers barely understand the minimum of EV knowledge, let alone how to preset these features and explain this to customers. Much more work is needed in the short term to get dealerships to understand and sell EVs first. • Could also include Preliminary interconnection paperwork? • Should not be a requirement, but OK as a "finders fee" incentive. Would need demos on these different ideas • This seems fairly burdensome as it would require much coordination between various entities (IOUs, vehicle dealers, charger technology providers, customers). Assume it would be easier to provide information for customers to sign up for TOU rates after they've received a vehicle rebate. Similarly, this might be a better way to advertise/incent customer adoption of smart chargers than through a dealership process.
2.12	• V1G is DR, not storage (slippery slope). Does V1G not have a path to fund pilots through TE programs? V2G is storage and SGIP could be explored, but see above response on incrementality of costs and best use of funds • This seems like it should have been consolidated with Recommendation 2.02. Timeframe might be too advanced. • Would be good to articulate why and how V1G specifically fits within SGIP. • I am not sure V1G should qualify for a storage-based program. V1G is not storage - there are several major differences that make V2G an inherently different product. • SGIP funding for V1G and V2G could potentially provide significant incentives • Pilots seem more appropriate at this time and ensuring that value of V1G and V2G applications is real and accessible before putting more funding into these applications. • VGI is a DER and should qualify. Similar to other SGIP ideas. It would need to meet rule 21

	• VGI is a DER and should qualify. Similar to other SGIP ideas. Would need to meet rule 21 • Consider whether receiving SGIP should obligate customer to participate in programs. Should protect ratepayers and address metering and settlement issues. • VGI would need to meet Rule 21 requirements but then should qualify • This recommendation needs further clarification of how it differs from recommendation 2.02. • Similar to 2.02. Not sure about V1G eligibility for SGIP as it wouldn't be "generating" anything • V1G is not storage, by any accepted definition. It does not belong in storage-related programs. It is load-shifting. • VGI is a DER and should qualify. Similar to other SGIP ideas. Would need to meet rule 21 • Other IOUs agree with adding resources for SGIP for EV as storage. It needs to meet rule 21. SGIP is based on statute, it may not be possible to expand it, or use funds for pilots without legislative direction
2.13	• V1G is DR, not storage (and CPUC determined as such), and storage mandate is achieved - this would do nothing to drive further V1G; V1G targets or carve-outs could be established similar to DRAM budget • Generally, I think this makes sense, but I'm not sure the timeframe makes sense- seems further out when EVs can be relied on for storage. • How would the capacity accounting work? Is the capacity contribution by V1G to meet the storage mandate equal to the full battery capacity? Or, is it equal to the average capacity participating in load curtailment? Something else? • I don't think V1G is storage. By this logic, all types of load curtailment should count - hot water heaters, HVAC, industrial load, all demand response in general. V1G is not storage - it cannot supply power, it cannot store renewable energy, metering is based on "what would have happened" - performance cannot be measured directly like a solar panel or battery discharge, there is no way of knowing actual capacity which is changing all the time, it's just not the same thing. If v1g gets SGIP / mandate it opens the flood gate for all DR, and now the mandate is pointless because would be instantly achieved. V1g should be benefited, but storage/generation needs to be sperate from load management, "supply" is not equal to "less demand". • LBL study showed V1G could be more cost effective than various other storage options in California • V1G charging and stationary storage are not the same thing and should not be treated similarly for the storage mandate. • This can be combined with CalETC idea. Need more details on implementation • can be combined with CalETC idea. Need more details on implementation • Need more details on implementation. • appears same/consistent with 2.23 • Enel X wants V1G to be fully valued and considered as a flexible balancing resource, but marked "disagree" for this recommendation as it's made through the lens of AB 2514 which is no longer relevant. We suggest the rec should read something like, "Ensure V1G is fully accounted for and valued as a candidate resource in the IRP, system and local RA solicitations, and other procurements for flexible balancing services" • V1G is not storage, by any accepted definition. It does not belong in storage-related programs. It is load-shifting. • can be combined with CalETC idea. Need more details on implementation • In support of technology neutral policies. Needs to details implementation.
2.14	• This recommendation seems like it's just trying to insert the use case framework into all TE systems. I find the use case framework burdensome-- it's extremely detailed but adding that much detail doesn't provide much added value. I don't think it should be inserted in all TE decisions just because. • This could provide further clarity regarding cost effectiveness of transportation electrification • It is not clear that there exists a cost-effective VGI use case in every situation. Not every TE program or project need have one. Deploying EVSE and reducing GHG emissions is the priority. VGI is a means to an end, not an end in and of itself. • Cost effective VGI is supported. Requires coordination between many agencies • We support cost-effective VGI. Requires coordination between many agencies • We support cost-effective VGI. Requires coordination between many agencies.

	• We agree with the value of documenting the use cases. However, we need to evaluate any proposed subsidies for the VGI use cases on a case by case basis before providing support or opposition. • Agree with the position that cost-effective VGI must be considered as a foundational element of TE investments under the TEF, per SB 676. Would revise the rec to loosen the prescriptive focus on "priority" or "high value" use cases in doing so, given the many subjective interpretations of this. • Possible this is referring to another document/the broader policy recommendation made by the same commenter • We support cost-effective VGI. Requires coordination between many agencies • We support cost-effective VGI. Requires coordination between agencies.
2.15	• I had the same initial reaction as the CPUC comment- EVSE projects should be incentivized for taking advantage of • Currently not much incentive for construction projects to include grid interconnection & EV infrastructure upgrades. • Installing and interconnecting EV infrastructure at the same of time of other construction projects can increase cost efficiency. • Not sure of the VGI nexus here nor the basis for incentives. • Siting near grid and where grid capacity is available is a strong method for lowering capital costs of infrastructure projects across in the commercial use case, however, implementation of this incentive could be overly complicated and unnecessary. Instead, frequently updated capacity maps to guide better siting is a lower cost method to guide siting.
2.16	• This could go into some sort of "market transformation" category. Although it doesn't say how to get to this point, just that it should exist. • SBUA believes this should help reduce costs for VGI communications. • This lowers cost of networking in two ways - competition between cloud aggregators, and through leveraging existing low-cost on-vehicle proprietary telematics • lowers cost of networking in two ways - competition between cloud aggregators, and piggybacks on existing low-cost on-vehicle proprietary telematics • Lowers cost of networking in two ways - competition between cloud aggregators, and piggybacks on existing low-cost on-vehicle proprietary telematics. • Active area for near-term scale-up projects with associated analysis, just what cost points include what levels of functionality and how to find the right trade-off in low cost and resulting impact. • Which VGI communication pathways is this recommendation suggesting that EVSEs accept? • Agree that this is extremely relevant and important, but ultimately "Disagree" based on the fact that communication protocols are supposed to be out of scope for this WG. Also doesn't seem to tie back to any specific VGI use case or application / benefits. • While Nuvve agrees that it would be beneficial to refrain from mandating communications standards the fact is communications standards are already mandated by multiple programs, the communications METHOD is not. Regardless, none of this has much to do with the aggregator. If we look at the implementation of IEEE 1547, we see that the aggregator actually enables multiple communications languages and methods to be used by end devices. Keeping this system in place is essential. • lowers cost of networking in two ways - competition between cloud aggregators, and piggybacks on existing low-cost on-vehicle proprietary telematics • Key to support lower cost of networking.
2.17	• This is similar to Recommendation 2.04 and adds in some building code elements. Generally makes a lot of sense to reduce cost and add demand flexibility. • How to address the concept of "performance guarantee" to ensure that the load management solutions are functioning reliably? • SBUA believes this would help cost-justify BTM load management. • Being technology agnostic is important to reduce customer confusion and metering/networking cost. Also will need strong regulations and customer oversight along with marketing/education to ensure that customers will comply with safety regs or automatic technology/software to ensure behavior.

	• To reduce customer confusion and metering/networking cost - being technology agnostic is important. Also need to comply with safety regs or automatic tech/software to ensure behavior • To reduce customer confusion and metering/networking cost - being technology agnostic is important. Also need to comply with safety regs or automatic tech/software to ensure behavior. • This needs clarification of how it differs from Recommendation 2.04. We support streamlining EV interconnection to the extent possible while maintaining a safe and reliable grid. • See comments to no. 2.04 • This is a critical component to Peninsula Clean Energy's upcoming EV infrastructure program. This type of load management is a critical component to scaling EVs and should be included in EV infrastructure for MUDs and workplace applications. • This recommendation should replace 2.04 and 6.05 • To reduce customer confusion and metering/networking cost - being technology agnostic is important. Also need to comply with safety regs or automatic tech/software to ensure behavior • To reduce customer confusion and metering/networking cost - being technology agnostic is important. Also need to comply with safety regs or automatic tech/software to ensure behavior
2.18	• This recommendation seems to be conflating port count with load management. Generally I think Recommendation 2.04 and 2.17 (mostly 2.17) are stronger on the load management language. But I don't disagree that single port chargers don't make a ton of sense cost wise (and usually design wise). • Power sharing can occur across separate EVSE; it doesn't have to be one EVSE with multiple connectors. Additionally, there is a balance to when multiple connectors are appropriate. EVSEs with multiple connectors are not universally optimal; depends on the situation at hand • Any managed charging through infrastructure MUST take into account customer travel needs and/or EV energy considerations. • Adaptive load management improves infrastructure's ability to more efficiently absorb excess daytime solar power, resulting in reduced loads during peak hours. • Power sharing destroys public charging customer experience and inhibits EV adoption and SB350 goals • Applies to all locations including larger homes • Applies to all locations including larger homes • Applies to all locations including larger homes. • There is a delicate balance here with customer expectations for a charge session but in general agree -- especially for workplace settings to avoid needs for people to e.g. relocate vehicles at mid-day • While we support this recommendation in principle, more detail is necessary for how this recommendation proposes that the CPUC manage to incent this action. • Load balancing should be adequately incentivized by rate design, customer or distribution upgrade avoidance, or another relevant value stream -- not simply for the sake of load balancing. • This is a critical component to Peninsula Clean Energy's upcoming EV infrastructure program. This type of load management is a critical component to scaling EVs and should be included in EV infrastructure for MUDs and workplace applications. • This recommendation is enabled by 2.17. However the result of the incentive proposed here is already achievable if a) 2.17 is adopted; b) rate design allows for it • Applies to all locations including larger homes • Industry trends are currently tracking towards power sharing; however, a requirement beyond current program guidelines could actually hinder deployment as current and near term commercially available products sufficiently meet EV demands. • Applies to all locations even large homes.
2.19	• Market needs to decide where to site EV charging infrastructure as well as the power level. • This is a solid concept but not necessarily a policy recommendation. This naturally happens by market forces, shown by Tesla and Ego locations. It's possible that this could be turned into a policy recommendation to facilitate this, like greater transparency from utilities on where there is additional site capacity, or from other entities that might be able to enable this. • More info needed about best locations to locate EV charging stations.

	• Many factors go into station design so while capacity maps are helpful, these cannot be the only determinant in where stations are located. • Unclear Recommendation; Higher power level charging will better promote EV adoption and SB350 goals • While we wish to see EV charging generally have high utilization, an EV charging network as a whole may include some low-utilization stations that serve to provide comprehensive coverage. They encourage EV adoption by showing that an EV can go anywhere, even if that route is not often taken. Low-utilization stations along these routes have a value that is not reflected in their utilization level. • unclear on policy recommendation in a market-based system • Seems logical enough - just how to implement where sites/installers are free to do what they want so what is the policy directive here? • While mindful that "last mile" EVSEs may still be useful to incentivize EV adoption, we support this recommendation. Ratepayer-funded infrastructure should be used and useful. This recommendation needs clarification of how the CPUC would estimate which sites would have higher levels of utilization. Additionally, while focus on utilization is important the customer experience is also important to promote EV adoption. The focus on utilization should not create unintended levels of queuing in the pursuit of high utilizations. Accordingly, a target levels of utilization should be set and continually reevaluated to balance high utilization with good customer experience. • Do not see the VGI nexus here. Also disagree that this is an issue for CPUC regulation, both at a site level or for broader EV infrastructure deployment or transportation planning -- economics should dictate this automatically. • Siting infrastructure in high-use areas leaves gaps in the system, disincentivizing truly widespread adoption and limiting adoption to areas within certain radius of existing charging infrastructure • Clarify "higher level kW charging" as DC fast charging. See suggestion 2.15. A low-cost, easy to implement recommendation would be capacity maps. Lead times for capacity improvements on the utility distribution network have been consistently longer, especially in urban areas that see the highest percentage of ZEVs and therefore have the greatest need for more ZEV infrastructure, but these urban areas are also • where capacity issues are likely to be the most prominent. • SB 350 and the DCFC program already address this and projects are well underway.
2.20	• Supportive assuming this is advocating for SGIP incentive for paired stationary battery - such batteries already qualify for SGIP, so is a separate program needed? • This is related to Recommendations 1.01 and 7.06 because they both relate to stationary batteries co-located with DCFC. I think it makes sense and there should be further consolidation. I think rebates make more sense than rate design (noting this if further consolidation is done). I'm not sure if "SGIP-style" is ideal or not, worth discussing. • Pairing DCFC with battery storage to avoid grid-upgrade costs and delays is indeed a very promising opportunity. However, the details of including this under SGIP specifically are not clear in this recommendation. Need to further explain the business model, and the economic implications, trade-offs, etc. • I believe this is already the case - for example, Electrify America already does this. • SBUA believes this needs to also consider SGIP for Type 2 charging when Type 3 isn't cost justified. • SGIP funds should be eligible for stationary storage paired with DCFC -- would be helpful if these applications were eligible for resiliency projects. • Electrify America is an SGIP participant for pairing storage with DCFC • Battery incentive costs should it be an extension of other battery/grid efforts in the LSE and not from transportation efforts. That being the case, it may be easier to implement this use case as there's some history already. Wondering if this incentive can be today? • Should battery costs come from transportation efforts or should it be an extension of other battery/grid efforts in the LSE. Can do this incentive today? • Should battery costs come from transportation efforts or should it be an extension of other battery/grid efforts in the LSE. Can do this incentive today?

	• More details are needed to determine support, but cost-effectiveness should be evaluated and program must be designed to prevent cost-shifting. • Need to clarify the eligibility of battery-backed DCFC for SGIP, which I believe is all about servicing BTM loads. (I could be wrong here). Would need to consider the value of an additional incentive alongside the value that storage can deliver against DCFC rate design • Should battery costs come from transportation efforts or should it be an extension of other battery/grid efforts in the LSE. Can do this incentive today? • It is not clear what SGIP-style means. What would be the funding source? is it the charging station or the EV that would be eligible for the incentive?
2.21	• Clarity on whether for distribution/local AS or CAISO AS, but such a program is worthwhile to further scope and develop • Sounds like a solid policy recommendation. • The recommendation seems to focus on "public chargers", but then describes the incentive for "building owners". It's also not clear why this is new: Isn't this, in principle, the concept of aggregation, and can be done through existing DR programs? • Achieving managed charging capability does not necessarily require smart/connected charging infrastructure (vehicle telematics). Any managed charging through infrastructure MUST take into account customer travel needs and/or EV energy considerations. • Public charging stations can certainly be helpful for providing ancillary services, but need to avoid tying-up a public station for ancillary while other EVs wait for the station. • As fast charging becomes more common, public charging may not be able to deliver such services due to short duration of charging, and especially via a long-term contract due to uncertainty (e.g. COVID-19 closures). Residential may be able to though. • We expect fairly low revenue to a typical site host for this. Transaction costs for resource certification and other requirements would need to be extremely low for this to be viable. • Some use cases for this action may require V2G pushing this further out on the timeline (i.e. > 2023) • Some use cases for this action may require V2G so this is further out on the timeline • Some use cases for this action may require V2G so this is further out on the timeline. • Is this proposing a pilot program that could potentially be further expanded, or proposing a market mechanism? If the latter, is a specific public EVSE ancillary service incentive necessary, or can this be paired with more general energy storage incentives mechanism (with potential modifications to accommodate public EVSEs)? • Enel X believes this recommendation pertains more to EVSPs rather than a policy change that the CPUC or CAISO can make. The recommendation to CPUC or CAISO should be: better enable market pathways for EVSPs to provide AS, both V1G and V2G, through DERP-NGR, and then EVSPs can aim to incentivize drivers thusly • Currently unclear how the various motivations of facility operators, drivers, and EVSPs will interact here, but should be demonstrated. • Some use cases for this action may require V2G so this is further out on the timeline • Payments should be based on the benefit the resource provides - and an extra premium should not be paid for certain technologies to provide this service. CAISO procures A/S and has set forth the requirements to provide those services. IOUs have enabled EVs to provide grid services through all source RFOs for distribution deferral services which EVs are able to bid into.
2.22	• IOUs have their annual DIDF RFOs for all DERs and we are supportive of EV/EVSP specific RFO - however, it may be worthwhile to consider alternative sourcing mechanisms as RFOs have proven challenging for DERs • Solid recommendation, needs to make sure that the RFO is oriented for EVs specifically and not generally DERs. • Maybe start with a pilot? • SBUA believes more info, including answers to CPUC questions, is needed. • How is this different than demand response to mitigate upgrades?

	• 3rd parties can currently participate in the Demand Response Auction Mechanism (DRAM). New EV specific policy isn't needed. Grid resources should be tech agnostic • 3rd parties can currently participate in the Demand Response Auction Mechanism (DRAM). New EV specific policy isn't needed. Resources should be tech agnostic • Third parties can currently participate in the Demand Response Auction Mechanism (DRAM). New EV specific policy isn't needed. Resources should be tech agnostic. • Tie-ins with 2.04 and 2.17. The DIDF / IDER should be equipped to consider VGI solutions for NWA procurements that look to defer distribution upgrades. Enel X far prefers the tariffed load management solutions proffered in 2.04 and 2.17 to a carve out in DIDF for VGI • 3rd parties can currently participate in the Demand Response Auction Mechanism (DRAM). New EV specific policy isn't needed. Resources should be tech agnostic • Utility distribution deferral RFOs have been available to all DERs that meet the grid need identified. We disagree with VGIC's recommendation for EVs to receive preferential treatment in solicitations as all DERs should have an equal playing field when bidding into distribution deferral projects.
2.24	• I amended this slightly for readability and re-submitted a couple of times: "Align LCFS smart charging framework with IOU TOU rates." I'm worried without this amendment that this won't make a ton of sense to survey participants. • In principle, agree, since LCFS credit should capture the benefits of switching to cleaner fuels, and the IOU TOU design is partially taking CO2 intensity into account. However, the relationship there is not direct. More thinking is needed on this recommendation. • SBUA recommends this be consistent with, and reinforce, CARB requirements. • Needs clarification, CARB's program is statewide and changes quarterly. Might not be possible to do this as IOU and POUs rates are different mechanisms on smart charging effectiveness back to CARB to align with their rules LCFS rules. • Needs clarification CARB's program is statewide and changes quarterly. Might not be possible to do this as IOU and POUs rates are different mechanisms on smart charging effectiveness back to CARB to align with their rules LCFS rules. • Needs clarification CARB's program is statewide and changes quarterly. Might not be possible to do this as IOU and POUs rates are different mechanisms on smart charging effectiveness back to CARB to align with their rules LCFS rules. • We concur that the questions raised in the CPUC's comments need to be clarified. • Unclear what the problem statement or proposed solution is here. • Also needs alignment with CCAs and other LSEs that might be providing 0 CI energy products • Needs clarification CARB's program is statewide and changes quarterly. Might not be possible to do this as IOU and POUs rates are different mechanisms on smart charging effectiveness back to CARB to align with their rules LCFS rules. • See Recommendation 7.02 • This policy recommendation is unnecessary because the current LCFS regulation already requires those generating credits via the smart charging pathway to be on an IOU TOU rate if available
3.01	• FERC would reject a technology-specific tariff as being discriminatory - V1G can participate through DR pathway and the focus should be on expanding access instead to be non-discriminatory within PDR model • It's possible that Recommendation 2.01 might align with this recommendation. • Do the utilities have the technical capabilities to track and then manage EV load on the distribution grid? At what level of granularity? Maybe this is a 3-5 years kind of recommendations? • SBUA supports the need to answer CPUC questions to determine feasibility. • Public charging customers may not have ability to adjust usage and higher differentials may impede EV adoption and SB350 goals. Unclear how this is different than demand response. • Agree with CAISO (Peter Klauer) that to reach large scale adaption, TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services

	• Agree with Peter Klauer (CAISO) that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services. • More details are needed to determine support. Questions posed by the CPUC should be answered. • This recommendation needs fundamental revisions. CAISO ESDER is for WS market pathways that IOUs have nothing to do with. • Utility demand response programs as-written do not preclude participation by aggregations of EVs • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • What is being proposed is CPUC jurisdictional, not CAISO jurisdictional as a part of ESDER 4.
3.03	• This is important, but it is unclear if there is anything incremental to what is already being done in ESDER - EV charging already has a path through PDR, so something more specific should be highlighted here • Generally creating more value opportunity at the wholesale market level seems useful. Recommendation 2.21 might add some specificity to this general recommendation. • Should be beneficial to have aggregators participate in real time energy and ancillary markets. • Public charging customers may not have ability to adjust usage and higher differentials may impede EV adoption and SB350 goals. Unclear how this is different than demand response. • Agree with CAISO (Peter Klauer) that to reach large scale adaption, TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer (CAISO) that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services. (No response to Q2) • We concur that the questions raised in the CPUC's comments need to be clarified. • The problem statement here needs revising. Enel X already provides services in RT energy markets via managed charging. V1G is also already able to provide certain AS (spin, non-spin) through PDR • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Needs clarity on CAISO market mechanisms to enable it.
3.04	• V2G should have both pathways available to them, but this may be more of a question of which to work on first to fix • I think this recommendation makes sense but again I recommend not forcing the use case framework into every policy decision. • Policy clarification could accelerate V2G PDR market. • Agree with CAISO (Peter Klauer) that to reach large scale adaption, TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer (CAISO) that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services. (No response to Q2) • Related to nos. 3.07, ### below. Agree much work is needed on WS market pathways to provide RA thru aggregated BTM V2G (and storage broadly). A note that you can already provide DA energy through V2G in PDR -- it's just that you can't export power to the grid to do so. • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Given RA paradigm is undergoing substantial change, this VGI proposal may require substantial rethinking.
3.05	• Is the first saying that CAISO should allow for that or currently allows for that? I'm not sure how EVs would participate in a market without participating in a market. • SBUA recommends there be more info provided about this proposal. • Agree with CAISO (Peter Klauer) that to reach large scale adaption, TOU and dynamic rate are most important with some need for aggregators of wholesale services

	• Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer (CAISO) that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services. (No response to Q2) • Intriguing concept that could streamline things, though have questions about the feasibility, or why AS resources are currently required to bid into energy markets. • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer (CAISO) that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services
3.07	• This recommendation seems useful in promoting MHDV & fleet applications of V2G. • Why the focus exclusively on "separately metered"? Shouldn't all customers with V2G capabilities be able to participate in these grid services and wholesale energy markets? • Pilots and coordination by state agencies are first steps. • Agree with CAISO (Peter Klauer) that to reach large scale adaption, TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Agree with Peter Klauer (CAISO) that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services. (No response to Q2) • Related to no. 3.04 above. Lots of pieces here and the call for clarification is meant to further crystallize the asks. Echo the need for a new MUA proceeding. • Agree with Peter Klauer that to reach large scale TOU and dynamic rate are most important with some need for aggregators of wholesale services • Given RA paradigm is undergoing substantial change, this VGI proposal may require substantial rethinking.
4.01	• Similar to what I have written on other use-case recommendations, I don't think the framework adds a lot of value and it seems like some of these are promoting the framework for the sake of the framework and nothing else. • SBUA believes this would provide greater clarity regarding relative cost effectiveness of use cases • can be combined with CalETC idea • Can be combined with CalETC idea • Need is clear. • Consider 3rd party approach to accelerate analysis (i.e. not volunteers). • This WG should also inform the IOU TEPs in addition to what is being proposed in the TEF (e.g. development of pilots, program requirements). • Not sure who would sign up for this task force, nor the purpose such analysis would serve. Any cost-effectiveness analysis of VGI should be coordinated through the TEF following the CPUC's implementation of SB 676. • can be combined with CalETC idea
4.02	• General concern of adding prescriptive requirements - should be voluntary and opt in • The market is strong for non-networked EVSE in many applications. Which agency would enforce this proposed mandate? • I don't think it's feasible to prevent more limited EVSE from being sold. But I think it aligns in intent with Recommendations 2.05 and 2.06, where government should not use ratepayer/taxpayer money on EVSE that does not have managed charging capabilities (at a minimum). • The ability to provide energy services can be equally initiated and built into the car, through telematics. The market, and customers, should decide whether they want to participate in energy services through "smartness" in the EV, in the EVSE, or not at all. • Achieving managed charging capability does not necessarily require smart/connected charging infrastructure (vehicle telematics).

	• Makes sense and would be helpful. Need more clarification regarding which EVSE L2 stations are most effective for energy services. • This type of mandate is ahead of the market and would result in less EV charging infrastructure being deployed due to a premature and unnecessary increase in complexity of Level 2 charging. • There is no justification for this unfunded mandate. • There exist regions and use cases in which simple low-cost EVSE are the most suitable option. • Smart functionality and energy services should be encouraged by market mechanisms such as demand response payments, but not forced on EV drivers or site hosts by an unnecessary regulation. • California has active grid services markets with many entities providing demand response and frequency regulation and competing to do so at the lowest price. Consequently, the anticipated revenue to any one EV is low, and will diminish through dilution as more EVs take to the roads. OCPP makes sense for public networked chargers so that site hosts aren't locked into vendors, but again, mandating it for all L2 EVSE is not appropriate. Other standards are still too early to mandate and the market needs consensus from both Auto OEMs, Utilities, and EV Charging Networks. • There is concern about network costs in homes and where kiosks can be used in commercial settings. Also don't want to hurt EV adoption through excessive regulation. Would need coordination with CEC and their vision of communication protocols for energy services. • concern about network costs in homes and where kiosks can be used in commercial settings. Would require CEC reg. Don't want to hurt EV adoption • Concern about network costs in homes and where kiosks can be used in commercial settings. Would require CEC reg. Excessive requirements that harm adoption should be avoided. • potential cost implications / alternatives exist • This recommendation appears to be under the jurisdiction of the CEC. • Similar to no. 2.05 above. Agree with the proposed requirement for smart chargers but not sure if it is out of scope here, along with the mentions of comms protocols • This will destroy the developing EVSE industry in California • concern about network costs in homes and where kiosks can be used in commercial settings. Would require CEC reg. Don't want to hurt EV adoption • Similar to 2.06 Managed charging capabilities ensures that EV charging can be managed in a way to minimize adverse impacts to the grid. • However the ability to receive utility signals may not be required for all managed charging use cases. (e.g. in some cases "set and forget" may be sufficient).
4.03	• That's quite high kW charging for home chargers. Is this recommendation saying there should be policy support for or against the installation of those systems? • SBUA requests more location-specific data for which locations would benefit most from mitigating high kW charging. • Worth further investigation. • We oppose the imposition of demand charges on residential customers. • This can have a large potential impact due to the amount of charging occurring in homes and due to the fact that form ost EV drivers 10-19kW charging is overkill. • large potential impact due to the amount of charging occurring in homes • Large potential impact due to the amount of charging occurring in homes. • Agree that anything above 10 kW at household level should be carefully considered. and potentially higher power is disincentivized, but not precluded outright if people really want to pay extra for it, like a gas guzzler tax • Targeted pilots may provide more concrete data than the more dilute system wide studies of the past IOU Load Research Reports. • Rate design, policies and cost responsibility for primary and secondary distribution upgrades through Rules 15/16 (or any new tariff developed through the TEF), and proactively distribution planning should adequately address these challenges. Otherwise CPUC policy should aim to accommodate, and not stifle, customer choice of different charging levels, which is purely market driven. • large potential impact due to the amount of charging occurring in homes

4.04	• Similar to what I have written on other use-case recommendations, I don't think the framework adds a lot of value and it seems like some of these are promoting the framework for the sake of the framework and nothing else. • Detailed cost analysis carries with it significant antitrust concerns. Not sure how to do this… • Need to add Societal Cost Test to other CPUC cost tests (TRC, RIM, PAC) to get full picture of actual cost effectiveness. • Current utility programs funded through ratepayers are based on SB 350. A cost-effective metric would require legislative input/changes. • References CalETC data program idea. Test for ratepayer funded programs should be SB 350 and not a new c-e metric • References CalETC data program idea. Test for ratepayer funded programs should be SB 350 and not a new cost-effectiveness metric. • Agree here and not on 4.01 as this has direct tie-ins with the CPUC's implementation of SB 676 under the TEF for ongoing IOU TE investments. Would encourage flexibility on implementation given the many specific recommendations spelled out here. • VGI working group should not be assessing via cost-effectiveness whether or not action should be taken. Action should instead be taken to level playing field and allow access/participation, then allow EVs to compete • References CalETC data program idea. Test for ratepayer funded programs should be SB 350 and not a new c-e metric • Test for ratepayer funded programs should be SB350 and not a new cost-benefit metric
4.06	• This makes sense although I think using the very detailed use case framework could take away from the effectiveness of this. • This should help clarify value proposition of use cases. • We support the proposed 3rd party VGI net value analysis. • The need for this should be considered through the CPUC's implementation of SB 676 through the TEF • VGI working group should not be assessing via cost-effectiveness whether or not action should be taken. Action should instead be taken to level playing field and allow access/participation, then allow EVs to compete • NREL is already doing a lot of research in the VGI space and could be a great resource, they may already have a lot of useful data this working group hasn't had access to. Certainly would be able to collect and filter market sensitive data about costs that the sub-group wasn't able to do. • More clarification needed on the end-use of the types of data analyses that would occur with this funding. • Extensive request that has been addressed in studies, modelling, demonstrations etc. already • This would help close the gap on VGU benefits and costs. • Funding for large-scale VGI demo can be quite distinct from that for Data programs and Studies. Would be important to clarify further and be more specific with the details. • This is really one of the most key next steps IMO -- we've learned a lot through recent pilots but there is a great deal more to learn in just the next few years that can help to guide next steps for CA. • I don't know the specifics of CalETC's proposal but generally using CEC funds for VGI makes sense.
5.01	• Not sure what warranty has to do with CPUC policymaking - not sure what this convening achieves; better to create programs, pilots, and technical pathways • Automakers seem to be the limiting factor for why V2G applications are not more readily available. • Staying within battery warranty limits can vary significantly by automaker and is not a clear-cut topic. A lot of discussion would be needed. • SBUA believes this needs to be addressed at local government permitting level. • The LEAF-to-Home technology has been demonstrated in Japan, and resilience purposes are likely the highest-value use case for V2G. • While we support energy resiliency for our customers, automakers make their own decisions on features and a capability based on developing or existing market needs.

	• Support resiliency. Automakers make their own decisions. Not in CPUC jurisdiction. Makes more sense as voluntary effort • Support resiliency, but automakers must decide to allow discharge under their warranties. • As noted in the "barriers" section this may or may not be actionable directly by the CPUC. • Seems to veer too much into "CPUC regulating the auto industry" territory • Automaker warrantee is a much larger process, better to get sweeping agreements. Customer purchase of bi-directional equipment not relevant to warranty • Support resiliency. Automakers make their own decisions • TBD
5.02	• Do this in near term in Microgrids Track 2 • This is both complementary and counter to Recommendation 2.08. I think it makes sense but there should also be incentives for microgrids. • EVs providing emergency backup is becoming increasingly critical in rural areas with high likelihood of PSPS events. • The LEAF-to-Home technology has been demonstrated in Japan, and resilience purposes are likely the highest-value use case for V2G. • Details of the exact objectives of the pilots need to be worked out, although those can be forthcoming. • Similar to 2.09 and 7.14 on pilots. "Agree" more here than on the previous pilots due to the PSPS resilience angle, which is immediately needed. • This is a near-term priority for Peninsula Clean Energy. This recommendation should apply to both residential and non-residential customers and begin with demonstrations. CCAs can facilitate these pilots for key residential customers (e.g. medical baseline) and commercial (e.g. critical facilities) • Application of EV for PSPS
5.03	• Support Title 24 reform as well as using pilots to validate use case to inform standards development • This generally makes sense but more specificity would be nice. Is it just asking for inverters? • Rule 21 should be expanded to allow for OEMs to self-certify vehicle performance/function per SAE 3072 specification. • SBUA supports and notes this will take several years. • The LEAF-to-Home technology has been demonstrated in Japan, and resilience purposes are likely the highest-value use case for V2G. • Technical requirements and standards should be developed for homes in risk areas that are possible going to use EVs as a back-up storage unit. • We concur that the questions raised in the CPUC's comments need to be clarified. Generally, we support this recommendation, but more details are needed. • Agree that this is immediately needed, especially to address PSPS events. More clarification sought on the specific problem statements and what needs to change in R21 v Title 24, and in external / non-state codes and standards. • Technical requirements and standards should be developed for homes in risk areas that are possible going to use EVs as a back-up storage unit.
6.03	• This needs more framing, not sure the meaning. But skeptical about forcing use case framework. • SBUA believes more details for these use cases, and greater awareness of benefits and costs, is needed. • SB 350 has the criteria for assessment of IOU programs. EPIC also has similar rules. • SB 350 is criteria for assessment of IOU programs. EPIC has similar rules • SB 350 is criteria for assessment of IOU programs. EPIC has similar rules. • Our understanding is that the recommendations filled out in the "Policy Category" sections are the recommended use cases • What are "these use cases"? Future of PRP submissions unclear and pending TEF decisions. • Possible this is referring to another document/the broader policy recommendation made by the same commenter • SB 350 is criteria for assessment of IOU programs. EPIC has similar rules
6.04	• Not entirely clear how NEM fits in with EVs here - is this a rates or interconnection recommendation?

	• As written this recommendation makes it sounds like there is already NEM for EVs which I don't believe to be the case. The timeframe for determining a crediting system for V2X seems premature. • This would help reduce much confusion among public about NEM programs and rates. • Could use clarification and refinement. Lots of different ideas here. • We are not certain that the NEM concept provides a robust and durable economic foundation for EV investment. NEM may not last as long as EVs purchased today. • many different ideas here • Many different ideas included in this recommendation, requires clarification. • needs simplification/clarification on EV applicability • The disagreement score could be changed to agreement if the issue of cost-shift created by the current NEM tariffs is addressed. Until then, we do not support NEM for V2G. • Similar to 1.14 and 1.16. More clarity sought on use case tie-ins with NEM tariff, or what specific values / applications are being chased • many different ideas here • Any simplification of NEM should be done in NEM proceedings. CPUC is engaged in NEM reform now. NEM should not be extended to EVs in any case
6.07	• I think that the state goal/target should be established following the pilots. • Agree on the principal, but 10MW for 2020-2021 might be too ambitious. Maybe reduce the goal to 1MW? • extreme-weather-resilient microgrids encompassing entire communities. • This is mid-term and not a short-term effort. There needs to be a pilot or demonstration (e.g. EPIC) to determine what proclivity of customers to participate, incentives needs and potential technologies. 10MW is overly prescriptive within 1.5 yrs. • Should be mid-term not short term. Needs smaller pilot (e.g. EPIC). 10MW is overly prescriptive within 1.5 yrs. • Should be mid-term not short term. Needs smaller pilot (e.g. EPIC). 10MW is overly prescriptive within 1.5 yrs. • goal should be to encourage adoption/learning • Besides some of the targets, this needs clarification of how it differs with recommendation 5.02. • Similar to 5.02, but focuses on FTM rather than BTMs sectionalized MGs • Should be mid-term not short term. Needs smaller pilot (e.g. EPIC). 10MW is overly prescriptive within 1.5 yrs. • why not vehicle-to-building? Think large fleets, large vehicles, large warehouses that aren't necessarily true "micro-grids" • Creating a mandated carveout for one technology over other technologies will likely result in higher overall costs. • The role of EV charging in microgrid resiliency use cases including PSPS should be considered alongside other resiliency technologies rather than as a mandated program. Note that there is nothing preventing IOUs or the CEC from pursuing investigation of this topic within EPIC or other existing programs. For example EV charge management within a microgrid is already in scope for the Redwood Coast Airport Microgrid EPIC project.
6.11	• V2G standards for AC are in process at SAE (J3072). V2G interconnect standards for DC are in place. • These are important topics but this recommendation isn't a recommendation, just topics to be addressed. • Can the required collaboration be achieved? • We agree in principle to this recommendation, but is unsure of what actionable items are needed. • Ultimately Neutral because Enel X doesn't believe the pursuit of a V2G AC interconnection pathway should be contingent upon outcomes from this WG. Auto OEMs need such a pathway to provide a long-term signal to capture the value, which does not require an outcome from this WG to demonstrate.
7.01	• TNC/ridesharing fleets are an important area of focus. Skinner's TNC eVMT bill might address some of these suggestions. One thing that is challenging to overcome with these suggestions is that TNC drivers

	could cash in all these perks and then stop driving for a TNC company. Seems difficult to provide such rich funding to individuals that aren't necessarily going to provide number eVMT as expected. • SBUA believes this needs to show that ratepayers should pay for benefits reaped by TNC companies and their drivers • Public charging customers may not have ability to adjust usage and higher differentials may impede EV adoption and SB350 goals. • This policy has three separate idea. Each should be evaluated on their own merits. Some ideas could be ranked higher • three separate ideas should be surveyed instead of one idea; some ideas could be ranked higher • Three separate ideas should be surveyed instead of one idea; some ideas could be ranked higher. • multiple policy recommendations here • Ratepayer-funded programs should not explicitly subsidize specific companies. • Need a clearer explanation on the VGI nexus. Also not entirely sure of the policy role to specifically provide solutions to the TNC/Rideshare segment, versus allowing the EVSP market to enable solutions to this segment through broadly available rates, programs, make-ready budgets, etc. • three separate ideas should be surveyed instead of one idea; some ideas could be ranked higher • Allow make-ready and CALeVIP style programs to qualify for rideshare/TNC. Additionally, vehicle support may further bolster benefits gained from rideshare electrification. • Needs more clarity on who benefits; does the implementation line up with larger policy goals regarding TNCs. Three separate ideas should be surveyed instead of one idea; some ideas could be ranked higher
7.02	• LCFS in its current state doesn't do a great job reaching drivers, as this recommendation points out. But it does make electric mobility pencil for smaller firms and provides funding for utility rebates. This recommendation would require substantial program changes and I'm not sure it would get the support required. • SBUA believes this may be difficult to administer, but supports because it could have substantial societal benefits. • LCFS is an incentive to build out infrastructure; forced channeling to other parties may reduce investment and impede SB350 goals • We consider that clause (3) of the recommendation could be partially satisfied by a variety of utility transportation electrification programs including education and outreach as well as make-ready. • seems like category 11 for non-VGI specific idea • Arguably belongs in Category 11 • Needs to be taken up at CARB and could prove contentious, esp. the piece about channeling 70% of credit proceeds back to drivers. Incremental low/zero CI credit generation pathways were recently adopted for residential charging, and could in theory be used to maximize credit generation for non-residential segments. High VMT does not equate to low/zero CI charging, and to me does not have an explicit VGI nexus (unless general GHG reduction is considered VGI, but to me that's electrification broadly and not grid integrated charging.) • seems like category 11 for non-VGI specific idea • CPUC should stay away from policy decisions related to LCFS except in the case of the programs that relate to LCFS that the utilities already receive from residential applications. • LCFS program elements such as smart charging, low-CI electricity accounting, incremental credits in place to better capture GHG benefits • #1 - vehicles with higher VMT are already rewarded with more credits because they'll have higher kWh usage, hesitant to use LCFS program to reward certain sectors over others. • #2 - related to recommendation 11.02.
7.03	• EPIC already has this aim but might as well continue to push for VGI applications. • Need collaboration between CEC and CPUC • covers a few different ideas • Covers a few different ideas • Would want to better understand what the overall objective is here -- to enable high value yet high cost / hard-to-implement UCs?

	• What does this add that current CEC program/upcoming program not have? • covers a few different ideas • Same comment as below: ensure that these funds are not duplicating research currently being undertaken by the national labs….
7.04	• This is not a bad idea but EVs are different than stationary systems, especially in the short-term. This could be integrated with Recommendations 2.13 and 2.23. • funding opportunity mentioned by CEC seemed focused on MHD, this is really for LDV • SBUA notes that further knowledge and details about stackable value streams are critical for VGI value proposition. • seems like other ideas under SGIP reform • Similar to other SGIP-reform ideas. • Similar to other suggested pilots for V2G school bus demos, fleets, and FTM/BTM MGs. Clarity sought as to the forum for the pilot and tested Use cases and applications. • V2G qualifies as storage already in California, there is no reason to demonstrate that it can compete with stationary storage, it will either meet technical requirements for procurements or it will not. • seems like other ideas under SGIP reform • Related to SGIP reform concepts. In support of pilots that provide data on V2G.
7.05	• Sounds like a solid policy recommendation. • Agree with the idea, but need further clarification on why V2G is important for Muni fleet specifically, when it comes to resiliency? Would the Muni building be used as a "refuge" in the case of emergency? • Mobile resiliency from municipal fleets could be very valuable. • These projects and programs must able consider how to provide resiliency to the FLEETS themselves, i.e., if a transit district goes to 100% BEV, how do they operate during a PSPS? • Value on testing V2G for Municipal fleets
7.06	• This aligns with Recommendations 1.01 and 2.2 • SBUA requests more details on how this applies to V1G. • needs to be fair to all DERs and pay for performance • needs to be fair to all DERs and pay for performance • Needs to be fair to all DERs and pay for performance. • Unclear what the problem statement is here or how these opportunities would be sought. • needs to be fair to all DERs and pay for performance • Fair to all DERs and performance-based payment
7.07	• Sounds like a solid policy recommendation. • It is not clear whether utilities are capable of doing this today, or in the timeframe proposed. This might be better suited for 2-5 years from now? • Aggregation and capacity mapping can also be done by OVGIP using vehicle telematics. So, this proposal should be opened up so it is not exclusive to networked infrastructure providers/operators. • SBUA notes that this needs more details, but seems worthwhile. • This is OK for pilots and determine how to get dynamic information. If executed on all efforts must be subject to consumer privacy laws • OK for pilots; existing ICA maps are not dynamic; needs to be subject to consumer privacy laws • OK for pilots; existing ICA maps are not dynamic; needs to be subject to consumer privacy laws. • This is already possible: The mapping of EV resources is the job/business model of the aggregator-means definition will commoditize that, and aggregator resource assessments can be coordinated with 2030.5 resource lists as IOUs transition to it. • OK for pilots; existing ICA maps are not dynamic; needs to be subject to consumer privacy laws • In support of pilots; existing ICA maps are not dynamic; needs to be subject to consumer privacy laws.
7.09	• I don't know the specifics of CalETC's proposal but generally using CEC funds for VGI makes sense. • Specifics are not clear. How would the agencies do the selection? Can EPIC process be leveraged for that? Should the agencies do the selection alone, or with input from stakeholders? • SBUA believes this needs to show cost justification to confirm $50 M program requirement

	• VGI pilots and demonstrations are a good way to prove technical feasibility and value of different applications to drivers. • VGI working group should not be assessing via cost-effectiveness whether or not action should be taken. Action should instead be taken to level playing field and allow access/participation, then allow EVs to compete
7.11	• Great idea. • Is this not covered in existing efforts, including IRP? Specifics are missing. • SBUA believes this would help cost-justify TE impact on grid. • We support this proposal, as it will allow for a better understanding of the indirect impact of EVs on ratepayers. • Grid planning assumptions beyond 5 years are entirely speculative. Need to better clarify the objectives of such a long-term planning analysis. • Extensive request that has been addressed in studies, modelling, demonstrations etc. already
7.13	• I'm not sure the feasibility or long-term benefit in making ratepayer money more accessible. • Would the IOUs still go through a stakeholder engagement process, to solicit feedback and partnership with other industry players? (Hoping the answer is Yes). • SBUA believes there needs to be more details on where and how streamlining of approvals is feasible. • Does the Advice Letter process proposed by the Draft TEF address this recommendation? • CCAs are fast moving and well positioned to lead on technology demonstrations for VGI with their customers. • We believe that a program allows for quick approval of demonstrations and studies for EV technology would be helpful to advance VGI, but not a priority compare to other Policy recommendations
7.14	• This sounds like a great pilot/funding opportunity to support electric MHDV. • Agreed on the importance of this pilot, but disagree with the statement referencing "versus greater complexity in consideration of many individual drivers for rideshare operations." I believe fleet solutions, both the one proposed here and the one focusing on Rideshare, are very worthy of our efforts. • Cooperation between stage agencies is critical. • Related to 2.09. Could be taken up in EPIC • Depot-based charging for customer accounts can concentrate EV infrastructure and allow for energy management. CCAs can play a role in these pilots by interfacing with customers and providing systems for energy management and renewables alignment. • [CALSTART] we see great IMMEDIATE potential for this in Silicon Valley w/ corporate commuter buses, which are rapidly electrifying, as well as with shared urban bus depots for public transit fleets. [VTA]This might be an interesting way to maximize transit agency charging infrastructure that tends to be underutilized during the mid-day. A couple of VTA's bus divisions are located in major employment areas with high tech companies providing commuter service. • Undertaking pilots that focus on managed charging and VGI for commuter-based fleets should provide excellent information to help further develop VGI for this vehicle segment. Additionally, we recommend that learnings from existing utility pilots and programs (including our EV Fleet program) be leveraged to help stakeholders better understand the impacts Fleet electrification efforts have had to date. Information related to learnings from our EV Fleet program can be accessed here: https://www.pge.com/en_US/large-business/solar-and-vehicles/clean-vehicles/ev-charge-network/program-participants/resources.page
8.01	• I submitted a combined version of this recommendation with 6.08 which is Recommendation 9.01. • Charging stations at MUDs and residential need more incentives. • We strongly support including EVSE in new parking facility construction. • We concur with the CPUC's comments that this recommendation appears to have significant overlap with Recommendation 2.15. • Not sure of the VGI nexus here.
8.02	• Sounds like a solid policy recommendation.

	• Accessibility to EV TOU rates should not necessarily be predicated on a sub metered circuit. See Policy Recommendation 1.04. • Would help reduce barriers to EV TOU rates applied via submetering. • We note that there are recommendations for and against submetering and think further discussion on this could be useful. • PEV submetering effort is ongoing and a workshop is coming up May 22 where an initial protocol will be discussed. • workshop coming up May 22 and protocol is being finalized. See CalETC alternative proposal • Workshop coming up May 22 and protocol is being finalized. See CalETC alternative proposal. • not clear on the connection with submetering • Critical for MUDs to receive TOU rates for charging that doesn't occur on their meter • workshop coming up May 22 and protocol is being finalized. See CalETC alternative proposal • the fundamental issue is actually access to EV rates at all (not just VGI rates). Without a separate meter you currently can't use PG&E's new commercial EV rate. So, this is a real barrier. And an unnecessary one. Submetering technology is very advanced and trustworthy nowadays.
9.01	• This is a consolidation of 6.08 and 8.01. • Very politically and financially difficult to apply this to existing buildings. • This seems to support EV infrastructure more broadly and does not seem directly tied to VGI. • We strongly support revising building codes to require or encourage a higher percentage of EV-ready parking spaces. This is particularly important considering the long lifetime of buildings. • CalGreen is optional. Like incentives that provide bonus for doing more • Utilities support CALGreen standards but do not set standards. • This recommendation appears to have significant overlap with recommendation 2.15, 8.01. The differences of this recommendation need to be clarified. • Unsure of the VGI nexus here. • Power management and load balancing need to be clear to developers, which it currently is not. Level 1 and power management should be strongly encouraged for long-dwell applications. • CalGreen is optional. Like incentives that provide bonus for doing more • While our understanding is that this is not in the CPUC's jurisdiction, we suggest the state to explore an alternative pathway for compliance through public DC fast charging, enabling infrastructure to serve more vehicles in addition to more PEV-ready parking space requirements. Clarify that the success w/ managed charging capability should be reserved for L2 and slower charging. • More Plug-in EV (PEV) ready parking spaces in new and existing buildings should help assure consumers of available charging infrastructure and therefore can help with great EV adoption. With more EVs there will be a great opportunity to incent charging behavior based on grid signals (e.g., through TOU rates). We wish to point out that such a requirement could still be helpful without funding from utility ratepayers who might not have the ability to assist with incentive payments envisioned by the recommended policy.
9.02	• I'd expand this to VGI, not just V2G. • Should be expanded beyond just V2G - also V1G and benefits of electrification in general. • SBUA believes greater public awareness is needed, but hard to cost justify without tangible easy-to-quantify benefits • V2G education is definitely needed. • could be combined with 9.03 • Could be combined with 9.03 • important / but many regulatory/technical priorities remain ahead of public awareness • We agree that ME&O is important in general but will need to evaluate on a case by case basis whether ratepayer funds is the most appropriate method to fund the ME&O. • Tie-ins with TEF ME&O discussions on how state agencies and IOUs promote VGI solutions as part of the TEF • This should not be a stand-alone policy. V2G education to gov fleets should be part of a larger outreach, vehicle replacement and infrastructure planning effort.

	• could be combined with 9.03 • helping fleets understand that spending more up-front to acquire V2G can pay off over time is critical
9.03	• Makes sense for customer adoption. • Agree, one condition that it would not be limited to "Dynamic" rate options but include all time-variant rates. • SBUA supports ME&O as valuable, but difficult to demonstrate the benefits. • Support. Marketing/education/outreach budgets need to be increased all around in TE filings. In terms of the education on rates, as the EV market grows beyond early adopter to mass market, more education on the rates to EV drivers will be needed. • We agree that ME&O is important in general but will need to evaluate on a case by case basis whether ratepayer funds is the most appropriate method to fund the ME&O. • Critical to ensuring success in the TEF and in the CPUC's implementation of SB 676 • Customer education should be inclusive and community oriented. It should also include level 1 charging.
10.01	• I don't disagree with statement, but it's not a recommendation. • VGI is helpful in meeting GHG reduction goals. • Public charging customers may not have ability to adjust usage and forced VGI load management may impede EV adoption and SB350 goals. • This is THE MOST important recommendation. While VGI may have some value to the grid, the focus of TE efforts and infrastructure must be to reduce emissions of GHGs and criteria air pollutants from transportation. • define actionable priority • Would amend the policy action and success to reflect the requirements of SB 676 and how it's implemented as part of the TEF • Not sure what this is recommending
10.02	• Framework can be helpful but it is not always very accessible or actionable - we shouldn't be beholden to using this if it boxes conversations in • I've noted above about not over-emphasizing the use case framework just for sake of reinforcing it. • SBUA believes this should be useful framework for identifying most valuable VGU use cases • Concern this is overly prescriptive • Concern this is overly prescriptive. • framework appears to be default foundation already • Using a consistent framework to communicate VGI use cases will better ensure policy efforts are aligned. • This seems to be more a recommendation about the VGI valuation framework rather than specific policy actions to enable VGI use cases and unlock value. The VGI valuation framework is indeed a helpful tool to characterize use cases and approach the question of VGI value. Ultimately, though, the CPUC should consider the approach and results from this WG, alongside other relevant considerations, in its VGI policymaking under the TEF. • Concern this is overly prescriptive
10.03	• It generally seems like an okay idea, but I think that this should be some sort of competitive solicitation rather than just handing over public funding to OEMs and EVSPs. • SBUA believes this is worthwhile but need more details. • Concern is that this is overly prescriptive. SB 350 is the governing legislation for CPUC regulation TE programs. See cell D56 for additional info. • Concern this is overly prescriptive; For CPUC the standard is SB 350 • Concern this is overly prescriptive; standard for CPUC-approved programs is SB 350. • Programs with formal collaboration between the LSE and the OEM and EVSP will allow the program to pool expertise and therefore allow for greater chance of success in demonstrations. • Too prescriptive, and no clear pathway or authority for implementation. • Needs clarity on which types of partnerships should be prioritized for which specific VGI use cases. But yes, relationships with CCAs are critical.

	• How does this differ from existing consortium-formation activities? • Concern this is overly prescriptive; For CPUC the standard is SB 350 • there are many types of entities that can be involved in pilots--not necessarily automakers or EVSPs. Large, sophisticated fleets of all kinds can likely participate w/ out either of those, for example.
10.04	• Generally agree with sentiment but I have not seen this letter it references. • Agency collaboration would help achieve unified policies. • A little vague but yes, more coordination would be good especially with regard to infrastructure planning and support efforts • We strongly support this recommendation in principle, as it will better ensure that the state meets its GHG reduction goals, and that the goals are met in a way that is most beneficial for ratepayers. The CPUC agrees with the CPUC's comments that this recommendation needs actionable items to achieve the greater interagency coordination. • No clear pathway or authority for implementation. Could maybe get addressed if SB 1183 on interagency coordination gets adopted. • Regulatory agencies work together today. The fact this proposal exists means significant effort may be necessary to identify root causes and reasonable, workable solutions.
10.05	• This is not a policy recommendation. • Staffing, for VGI or otherwise, is an internal decision made by the respective stakeholders; it is not a decision to be taken or controlled by the State Agencies. With more than 100 recommendations addressing various calls for action on VGI, it is clear that VGI is an integral piece of California's efforts addressing TE. To us, we see this as an opportunity, and will staff accordingly, to ensure seizing this opportunity and helping CA find the right resources to meet its ambitious goals. • SBUA believes this needs more details and better communication between stakeholders and state agencies. • We concur that the questions raised in the CPUC's comments need to be addressed for this recommendation to be actionable (i.e. providing specific examples of where the CPUC has overloaded stakeholders, and also proposals to streamline the process). • Unclear what the problem statement or proposed solution is here. • Not sure if this is just a general comment on the workload? • The timeline of this VGI working group was nearly impossible for many organizations to keep up with an engage in, when there are concurrent activities, even within this PROCEEDING at the CPUC with overlapping deadlines. Most non-IOU orgs have 1, maybe 2 staff to cover all regulatory agencies in CA. • Needs clarity or specificity of issues that should be addressed. May be duplicative of precious item (10.04)
10.06	• Not sure what this is • I'm not sure what this recommendation is getting at. • Recommendation not clear. • SBUA believes this needs more details about Virtual Genset model. • CPUC questions were not answered. I makes it hard to definitively respond to this policy. • Amzur doesn't answer CPUC questions • Unclear what the problem statement or proposed solution is here. Unclear of the VGI nexus. • Is this referring to emergency back-up/islanded operation? • Amzur doesn't answer CPUC questions • Not clear. Amzur does not answer CPUC's questions.
10.07	• Unclear what this includes so can't say if I'm for or against. • Agree with the spirit of the recommendation, but more specifics would be important to make the recommendation actionable. • Which regulations of EVSE VGI capabilities are most important to modify? • Keeping it simple helps more EVSE infrastructure get deployed near term. • "Over-regulation" is subjective and this recommendation is unclear. • Already requirements by CPUC on EVSE, but CEC and CARB don't • more specifics would be helpful

	• This recommendation needs clarification to be actionable by the CPUC, e.g. examples of past over-regulation, or things the CPUC should not regulate. • Stating "disagree" solely from the angle of HW reqs and comms protocols being out of scope fort this WG • Needs more clarification on which regulations are already posing a problem or risk areas for potential over-regulation concerns in development • Applies to all EVSE, but particularly to VGI EVSE, particularly considering calls in this group and others for all EVSE to have VGI capabilities • Already requirements by CPUC on EVSE, but CEC and CARB don't • Overregulation of EVSE specifications can lead to higher costs and lower levels of deployment where charging is needed most. It's critical to note that multiple state agencies have been pushing for conflicting EVSE regulations on different timelines; coordination between agencies is key. • Without clarity it is difficult to assess the impact of this proposal. Generally it is a bad idea to overregulate, but CPUC should rely on expertise to determine what is necessary to ensure safety, reliability, affordability and to address consumer protection. This is especially important with small market entrants.
10.09	• My understanding is that this is controversial and I think it needs to be evaluated outside of the survey. • While we agree with this recommendation, this recommendation might be out-of-scope, since this WG agreed to not address technology-specific aspects of VGI. • Open standards are critical. • Generally support open standards, but the policy description in column F should be more prescriptive. In addition, any EVSE should abide by the SB454 Open Access regs developed by CARB. • VGI should utilize (or modify) existing standards for utility communications with DERs and Load management rather than develop a new VGI standard. (E.g. IEEE 2030.5, OpenADR etc.) • Utilities should not be required to integrate with multiple proprietary protocols or vendor specific APIs. • more specifics would be helpful • Comms protocols are out of scope for this WG. • Need clarity on which types of integrations are needed here beyond OCPP. • Aren't required standards generally already open? • VGI should utilize (or modify) existing standards for utility communications with DERs and Load management rather than develop a new VGI standard. (E.g. IEEE 2030.5, OpenADR etc.) • Utilities should not be required to integrate with multiple proprietary protocols or vendor specific APIs.
10.10	• VGI should be optional and incentivized, where capability requirement is one step below performance requirement, but it could potentially be counterproductive • Medium/Heavy duty charging systems may be unidirectional and not necessarily fitted with volt/VAR or other ancillary services capability. OCPP should not be listed explicitly since it is not yet a formal standard and must also go through cyber security testing. • My understanding is that this is controversial (the standards part) and I think it needs to be evaluated outside of the survey. • While we agree with this recommendation, this recommendation might be out-of-scope, since this WG agreed to not address technology-specific aspects of VGI. • Achieving managed charging capability does not necessarily require smart/connected charging infrastructure (vehicle telematics). • SBUA believes this is critical, but need more details on benefits and costs. • Public charging customers may not have ability to adjust usage and forced grid services may impede EV adoption and SB350 goals. • There exist many markets for grid services in CA. These markets may induce EVSE site hosts to install systems with such capabilities. If the revenues are not enough, or the site hosts simply do not wish to do so, they should not be mandated to. See our comment on D54 too: OCPP makes sense for public networked chargers so that site hosts aren't locked into vendors, but again, mandating it for all L2 EVSE

	is not appropriate. Other standards are still too early to mandate and the market needs consensus from both Auto OEMs, Utilities, and EV Charging Networks. • CPUC questions were not answered. It makes it hard to definitively respond to this policy. Additionally, a pilot is needed to determine which energy services has market pull. • is this for CEC or PUC? No Amzur response to CPUC questions. Needs testing for relevancy • Unclear. • potential cost implications / multiple consideration here • This needs clarification of how it differs from Recommendation 4.02, besides applying to ML EVSEs rather than L2 EVSEs. • HW reqs and comms protocols are out of scope for this WG. • Over-specification should be avoided. • is this for CEC or PUC? No Amzur response to CPUC questions. Needs testing for relevancy • It needs to be clarified what type of entity would make such requirements for all ML EVSE or Charging Stations to have the ability to provide these stations and whether or not these requirements would make ML EVSE and Charging Stations cost prohibitive and therefore counter-productive to EV infrastructure advancement.
10.11	• VGI should be optional and incentivized but not required - caution against across-the-board requirements that only adds cost and does not reward best performers (see headroom or frequency requirement for inverter-based gen at wholesale gen level) • Medium/Heavy duty charging systems may be unidirectional and not necessarily fitted with volt/VAR or other ancillary services capability. OCPP should not be listed explicitly since it is not yet a formal standard and must also go through cyber security testing. • I think a vast majority of HL charging stations can provide energy services. I'd need to understand if this effectively does anything. • Not clear on the reasoning behind this recommendation. Need further explanation. • SBUA supports this as critical, but need more details on benefits and costs. • Public charging customers may not have ability to adjust usage and forced grid services may impede EV adoption and SB350 goals. • There exist many markets for grid services in CA. These markets may induce EVSE site hosts to install systems with such capabilities. If the revenues are not enough, or the site hosts simply do not wish to do so, they should not be mandated to. See our comments on D54 too: OCPP makes sense for public networked chargers so that site hosts aren't locked into vendors, but again, mandating it for all L2 EVSE is not appropriate. Other standards are still too early to mandate and the market needs consensus from both Auto OEMs, Utilities, and EV Charging Networks. • CPUC questions were not answered. I makes it hard to definitively respond to this policy. Additionally, a pilot is needed to determine which energy services has market pull. • is this for CEC or PUC? No Amzur response to CPUC questions. Needs testing for relevancy • Unclear. • potential cost implications / applicable to any >500 kVA load? • This needs clarification of how it differs from Recommendation 4.02, besides applying to HL EVSEs rather than L2 EVSEs. • HW reqs are out of scope. Disagree with any kind of compulsory requirement for EVSE energy service provision. Provide EVSPs with rates, tariffs, programs, and market pathways and they can decide to provide energy services. • Over-specification should be avoided. • is this for CEC or PUC? No Amzur response to CPUC questions. Needs testing for relevancy • certainly these types of charging stations will have significant grid impacts, but also can be significant grid assets. So, since there will likely be significant ratepayer investment to enable such stations, it seems reasonable to require that they provide grid & energy services, however it seems like we should focus more on ensuring structures that would incent this in the first place. • Could make HL Charging Stations cost prohibitive and therefore counter-productive to EV infrastructure advancement.

10.12	• Sounds like a solid policy recommendation. • Need to ensure that semi-annual reports are actually considered and utilized by state agencies. • Best if combined with CalETC's VGI Data Program task force • Best if combined with CalETC's VGI Data Program task force. • support ideas in principle / must consider what is the most effective mechanism to deliver input • Need to address the jurisdiction and authority here. This could potentially be enabled by the cross-agency EV infrastructure council that would be established under SB 1183. • Progress reports/updates are a good idea as changes recommended in this group are implemented, to address unintended consequences and continue to progress. • Best if combined with CalETC's VGI Data Program task force • As long as the recommendations can be acted upon by the parties receiving the reports and are policy based in nature, this task force can be successful in identifying and removing technological barriers currently present in the EV space.
10.13	• Sounds like a solid policy recommendation. • Need to ensure that semi-annual reports are actually considered and utilized by state agencies. • Best if combined with CalETC's VGI Data Program task force • Best if combined with CalETC's VGI Data Program task force. • support ideas in principle / must consider what is the most effective mechanism to deliver input • SB 1183 • Progress reports/updates are a good idea as changes recommended in this group are implemented, to address unintended consequences and continue to progress. • Best if combined with CalETC's VGI Data Program task force
10.14	• Sounds like a solid policy recommendation. • Need to ensure that semi-annual reports are actually considered and utilized by state agencies. • Best if combined with CalETC's VGI Data Program task force • Best if combined with CalETC's VGI Data Program task force. • support ideas in principle / must consider what is the most effective mechanism to deliver input • SB 1183 • Progress reports/updates are a good idea as changes recommended in this group are implemented, to address unintended consequences and continue to progress. • Best if combined with CalETC's VGI Data Program task force • We support the voluntary taskforce but suggests this encompass all DERs and not just VGI. CAISO does have an intake process for new initiatives/enhancements that are open year-round as a part of their Annual Policy Initiatives Roadmap Process.http://www.caiso.com/informed/Pages/StakeholderProcesses/AnnualPolicyInitiativesRoadmapProcess.aspx
10.15	• Sounds like a solid policy recommendation. • SBUA believes this needs to ensure that semi-annual reports are actually considered and utilized by state agencies. • Best if combined with CalETC's VGI Data Program task force • Best if combined with CalETC's VGI Data Program task force. • support ideas in principle / must consider what is the most effective mechanism to deliver input • SB 1183 • This should include CCAs and other LSEs • Progress reports/updates are a good idea as changes recommended in this group are implemented, to address unintended consequences and continue to progress. • Best if combined with CalETC's VGI Data Program task force
11.01	• This relates to Recommendation 1.01. • Need a policy which does not have low income ratepayers subsidize middle and high income ratepayers

	• Need to better understand demand responsive component that gets scaled with utilization; utilization may vary over time (up and down) depending on whether new stations are built around this one and use case etc. • Demand charges are a threat to EV adoption and SB350 goals, however increasing with utilization may still impede VGI goals • Cost-causation might not be met with this proposed policy. • concern over cost-causation might not be met • Utility rates should follow principles of cost causation. • We support the reduction of demand charge, but not the elimination. Distribution costs vary more closely with demand than with system-wide TOU pricing signals, so some demand-based charges can be justified. This recommendation needs further specifics to be actionable. The CPUC appears to already be aware that demand charges can be prohibitive for public and commercial EV charging. Is this proposing specific changes beyond the IOUs' proposed and implemented commercial EV rates? • Needs to be revised to reflect previous and current work on commercial EV charging rates across the three IOUs, as well as how the draft TEF proposes to handle rate design issues. That said, not a super clear nexus with VGI. • Depends on other rate design factors • concern over cost-causation might not be met • Additional optional rate options in addition to what has already been approved by the CPUC could be beneficial. • At this time, our rates are sufficient to achieve what I believe the intent of the policy is, but the policy is contradictory from beginning to end.
11.02	• This relates to Recommendation 7.02, perhaps consolidation should be considered. ARB currently encourages this but while drivers usually don't see the LCFS credit directly, the credit value is baked into the cost of chargers, EVs (through utility rebates), etc. • Need more details on how the LCFS benefits could be shared between host site and EV owner • Unrelated to VGI. • LCFS is an incentive to build out infrastructure; forced channeling to other parties may reduce investment and impede SB350 goals • LCFS funding is a potential incentive for development of EV infrastructure. While we appreciate that utilities may devote some LCFS funding towards EV efforts, it would be good for some LCFS funding to go to EVSE site hosts, EV dealerships/OEMs, or EV drivers. Recommendation 7.02 is clearer on this point. • This isn't a VGI policy. CARB already gives the credit to the site host who then decides who to share it with, if anyone • note really a VGI. CARB already gives the credit to the site host who then decides who to share it with, if anyone. If by site host, residential charging is meant, then this sharing is about to occur via the Clean Fuel Rewards program • Not strictly VGI. CARB already gives the credit to the site host who then decides who to share it with, if anyone. • Recommend providing the information in the "Notes" Section into the "Policy Action" section. • This already exists for LCFS -- in as much as default credit generators are able to assign rights to 3rd parties to monetize, in exchange for reducing the up-front cost of EV installations. Not sure what the problem statement is unless the intent here is to make it compulsory. Also, no clear VGI nexus. • note really a VGI. CARB already gives the credit to the site host who then decides who to share it with, if anyone • This would require changes to CARB regulation and would be extremely difficult to do if the technology to accurately and easily track usage is not available
11.03	• What can the CPUC do here? • This is an important topic but this isn't a recommendation. GOBiz has created a guidebook on this. Perhaps the recommendation can be training funds to educate local governments (who design the local

	permit process)? Is there something in the GOBiz guidebook that's missing or incorrect? This isn't actionable but it is important. • SBUA believes more details are needed on which permits need to be streamlined and how. • May or may not be related to VGI specifically. • Permit issues are an impediment to public EV charging infrastructure and cause unnecessary costs and delays • Outside scope of VGI WG. • Is this something the CPUC can address, or would it primarily be through another agency? • No clear VGI nexus. • Permit streamlining should also include education for permitting officials on energy load management, which can provide confusion and delays in permitting • While not in CPUC's jurisdiction, EVgo recognizes the work being done in the state to permit streamlining. Permitting remains extremely critical to ensuring projects are able to move forward in an expedited manner & not unnecessarily delayed/halted. • Would support VGI significantly
11.04	• ADA does stop a lot of projects from happening but similar to the recommendation above, this isn't a recommendation, just an area of concern. This is also politically sensitive. • Need closer look at ADA requirements that sometimes are very burdensome without corresponding benefits for disabled drivers. • Unrelated to VGI. • Outside scope of VGI WG. • Is this something the CPUC can address, or would it primarily be through another agency? • No clear VGI nexus. • Results from this finding should inform other state policy such as technical requirements in CEC funding that requires parking to be reconfigured (such as funding requirement that require stations to be shared instead of individually assigned. The former triggers an ADA upgrade, the latter does not). • Would support VGI significantly
11.05	• Perhaps utilities can be partners for make-ready and necessary electrical upgrades? • Can make use of some more specifics: Is the idea that, once a construction project is identified in an existing or new parking lot, there is some sort of incentive to make sure that the parking lot gets new EVSE installed, on the top of whatever construction project was originally scheduled? • SBUA strongly supports this to help ensure EVSE is installed in public parking spaces where beneficial. • This is already proposed in the Charge Ready 2 proposal. • Example in Charge Ready 2 proposal • Outside scope of VGI WG. • Installing and interconnecting EV infrastructure at the same of time of other construction projects can increase cost efficiency. • No clear VGI nexus, save for the call-outs for V1G and V2G, though not sure how those serve as the basis for incentivizing new construction • Example in Charge Ready 2 proposal

ANNEX 9: SURVEY SCORES ON POLICY RECOMMENDATIONS

A total of 28 responses to the survey were received, with most responses containing answers for all 109 policy recommendations. Responses were received from CalETC, CESA, Charlie Botsford, Electrify America, Enel X, Energy Innovation, Engie, EVGo, Fermata, Ford, GM, Greenlots, Kitu Systems, LADWP, MHDV Team, NRDC, Nuvve, Public Advocates Office, Peninsula Clean Energy, PG&E, Plug In America, SBUA, SCE, SDG&E, Sumitomo, Tesla, Tim Lipman, and UCS. The identities of respondents in survey results are currently being kept anonymous.

The individual survey submissions are available for viewing and analyzing in the Policy Recommendations Database, including all the individual comments for each policy recommendation.

The average score for each question Q1, Q2, and Q3 is given in the database, including the number of survey responses tallied for a given policy recommendation.

The graphs below show the distribution of scores for Q1, Q2, and Q3 for each policy recommendation. And the attached three graphics convey the mean score for Questions Q1, Q2, and Q3 for each policy recommendation. The survey questions and responses were as follows (see Annex 2 for more details):

Q1. Do you agree or disagree that this recommendation will advance VGI in California?

5 - Strongly agree
4 – Agree
3 – Neutral
2 – Disagree
1 – Strongly disagree

Q2. How clear, understandable, and policy ready is this recommendation?

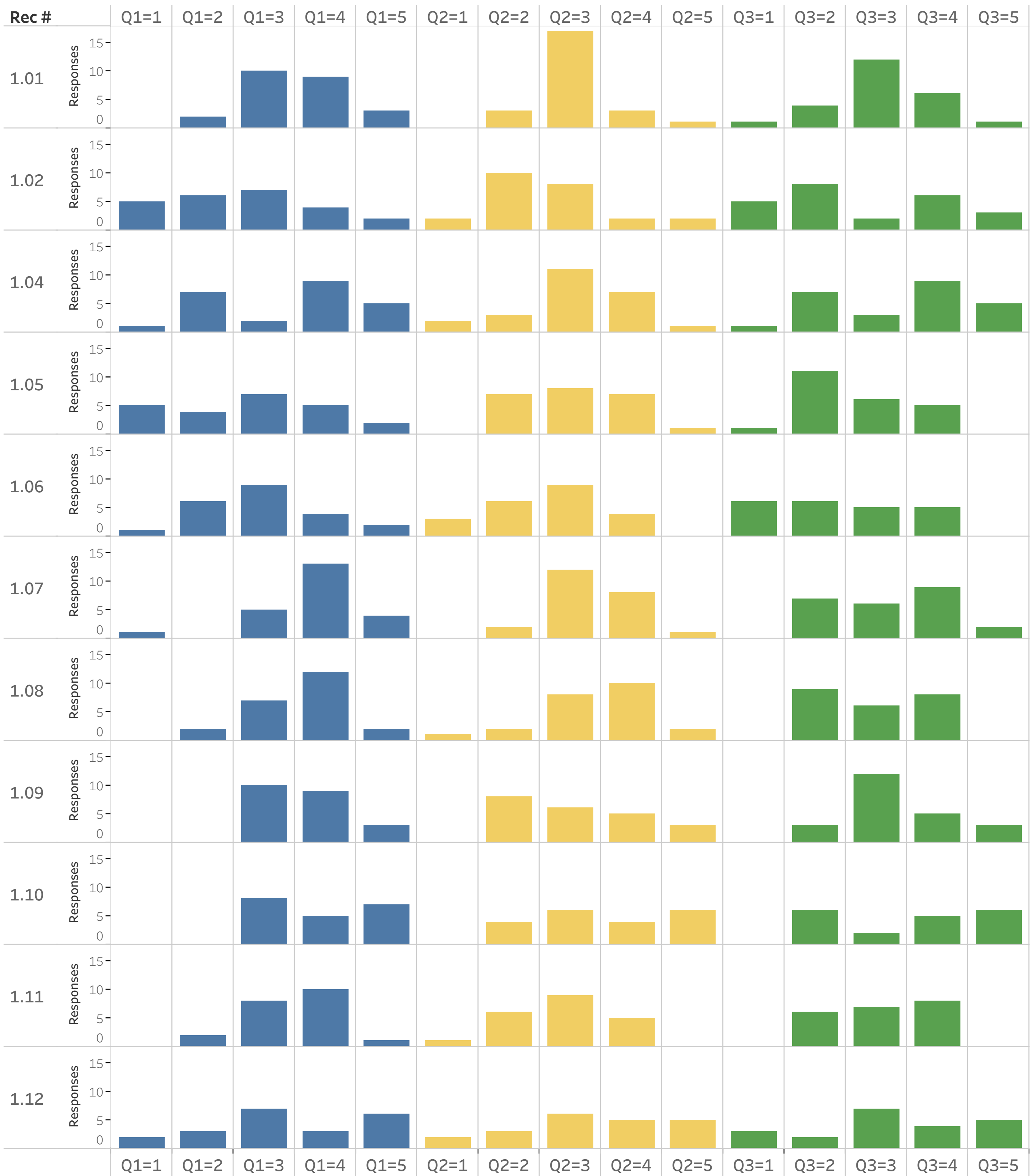
5 - Perfectly clear and policy ready
4 - Sufficiently clear and policy ready
3 - Needs some clarification
2 - Needs substantial clarification to be policy ready
1 - Needs to be re-written or re-thought

Q3. How critical and relevant is this policy to meeting your organization's own VGI objectives?

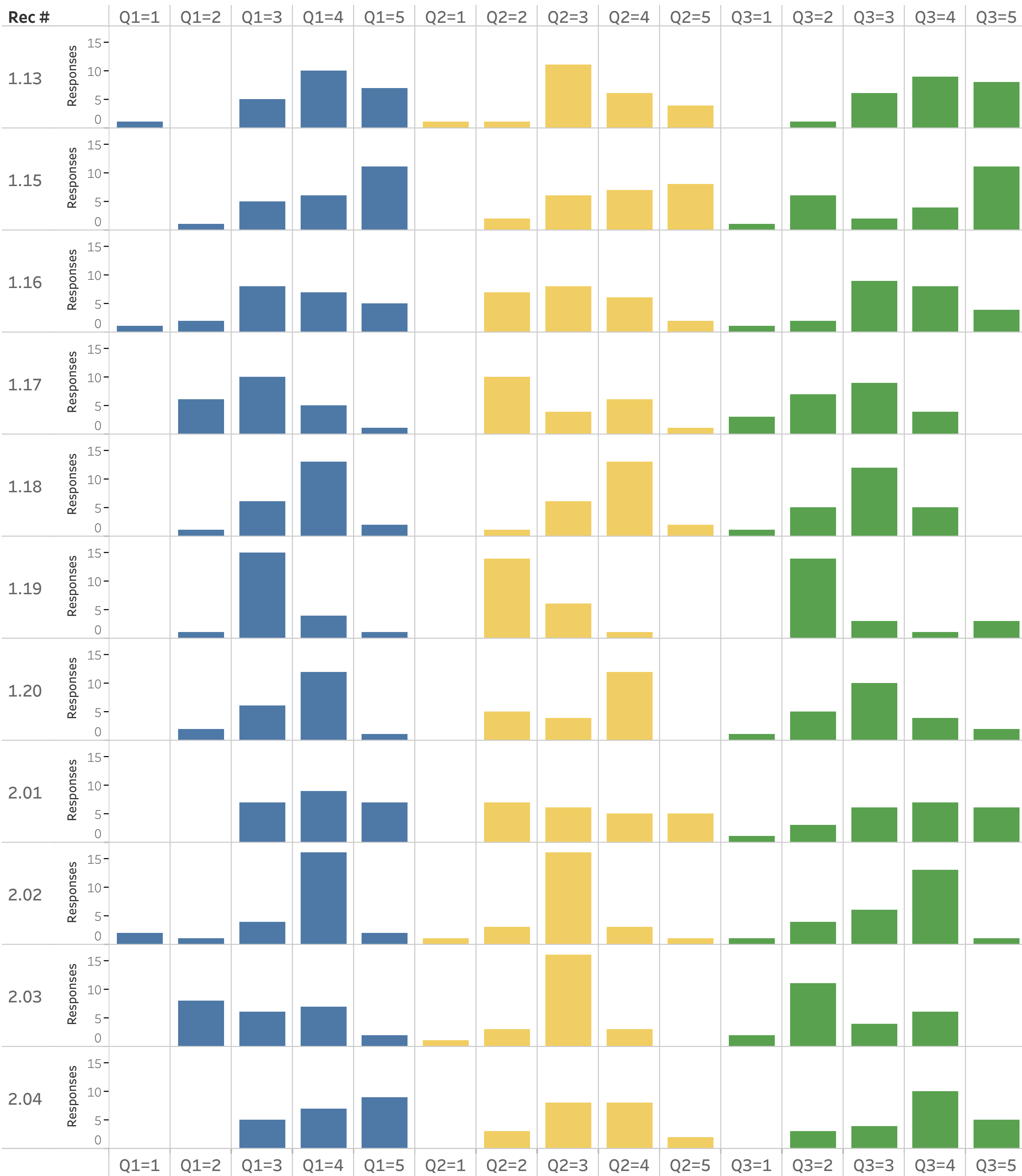
5 - Extremely critical and relevant
4 - Critical and relevant
3 - Not critical but still relevant
2 - Might be relevant
1 - Not relevant

Q4. Any other comments on this recommendation? Include any notes about how you see this recommendation connected to any of the other recommendations, including overlaps or complementarities.

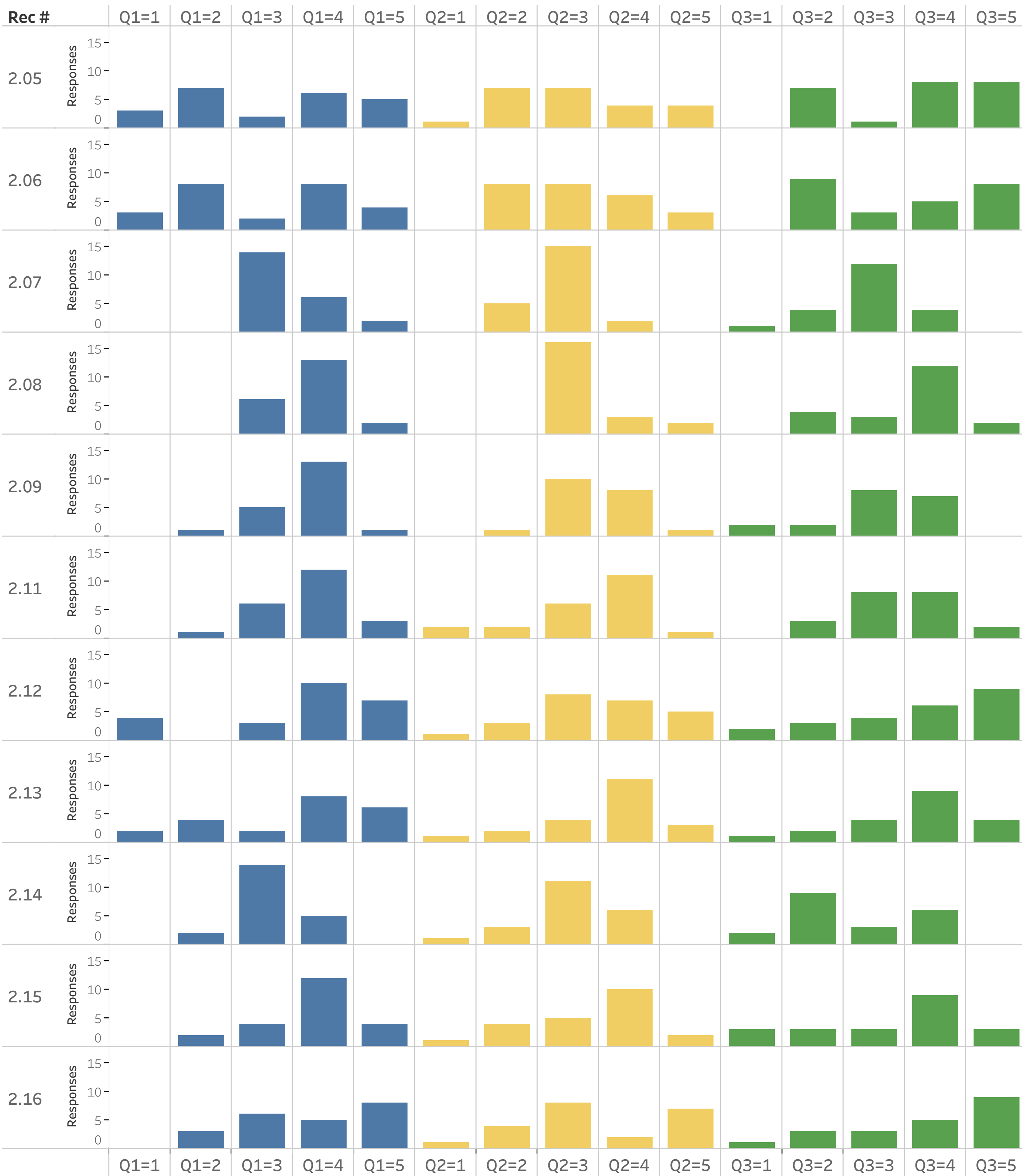
Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)

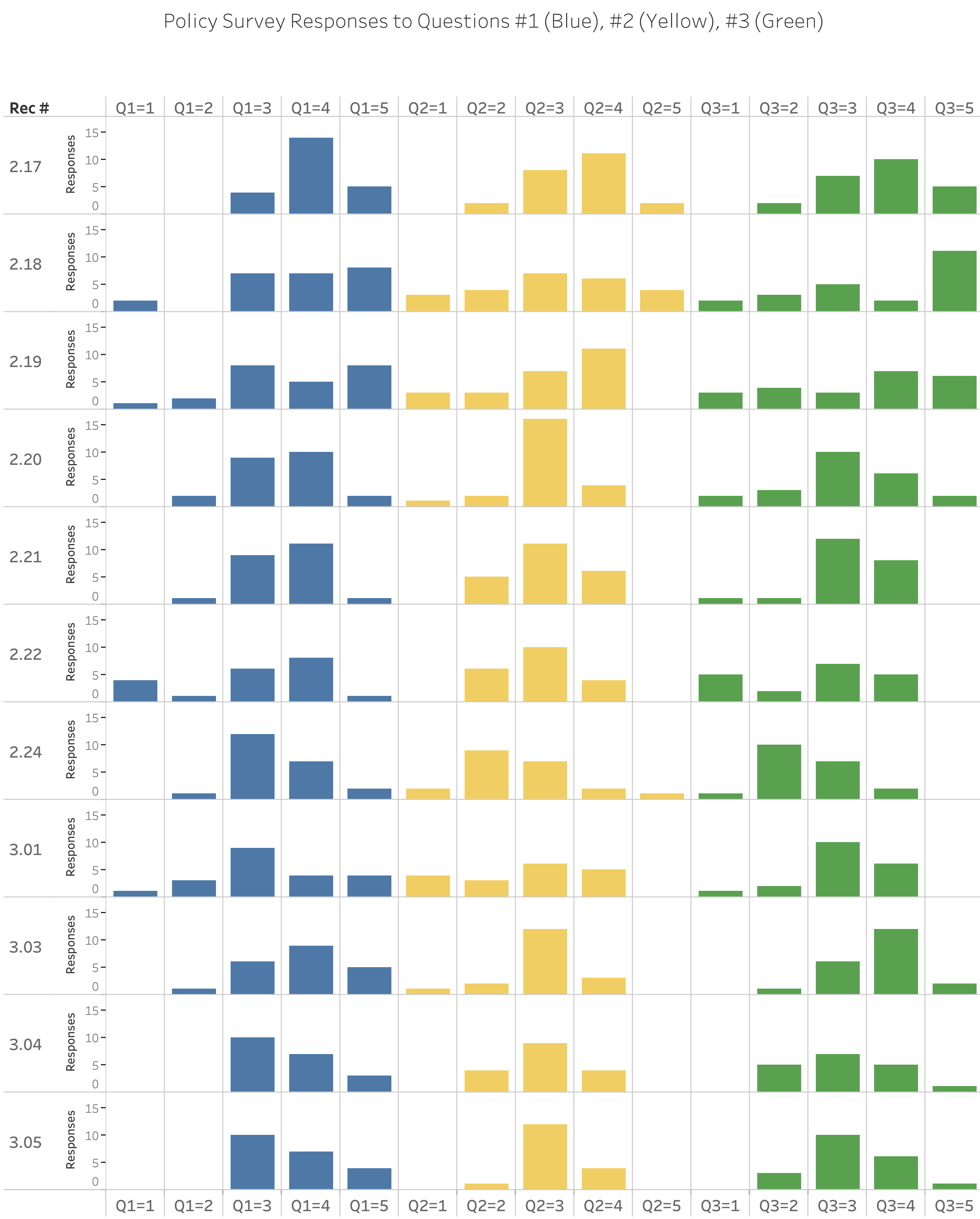


Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)



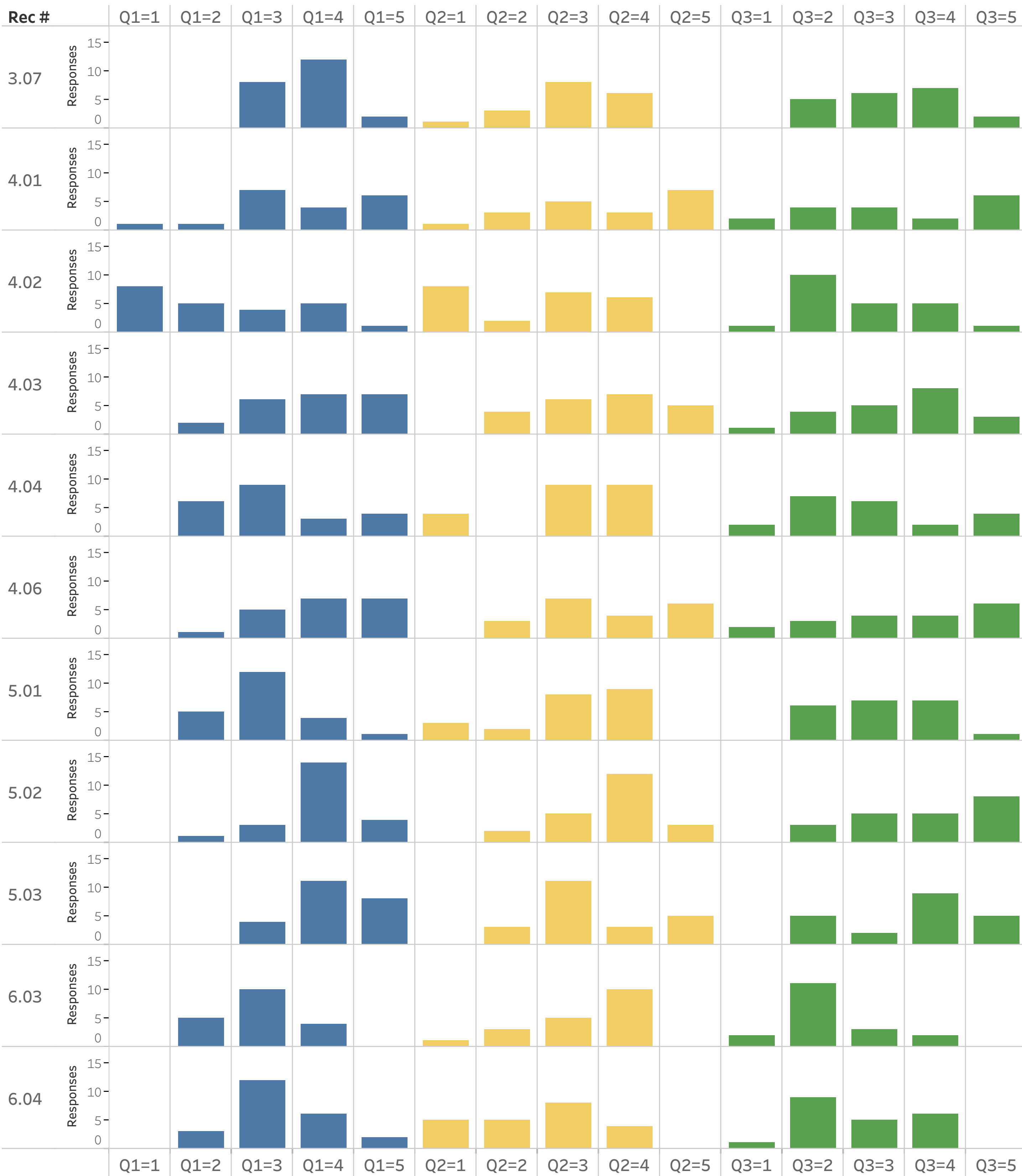
Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)



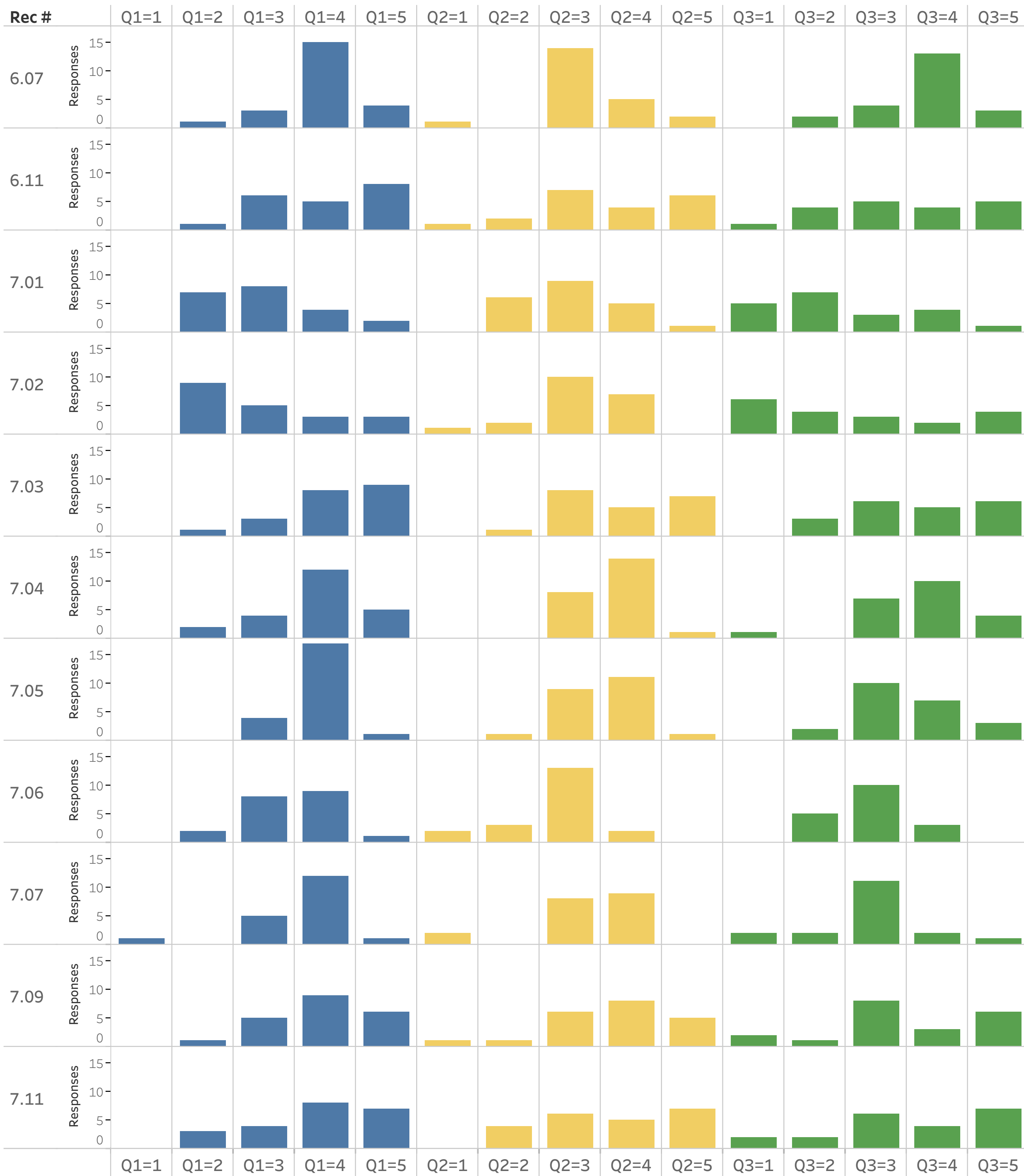


Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)
Rec #
Q1=1
Q1=2
Q1=3
Q1=4
Q1=5
Q2=1
Q2=2
Q2=3
Q2=4
Q2=5
Q3=1
Q3=2
Q3=3
Q3=4
Q3=5
2.17
2.18
2.19
2.20
2.21
2.22
2.24
3.01
3.03
3.04
3.05
Responses
0
5
10
15

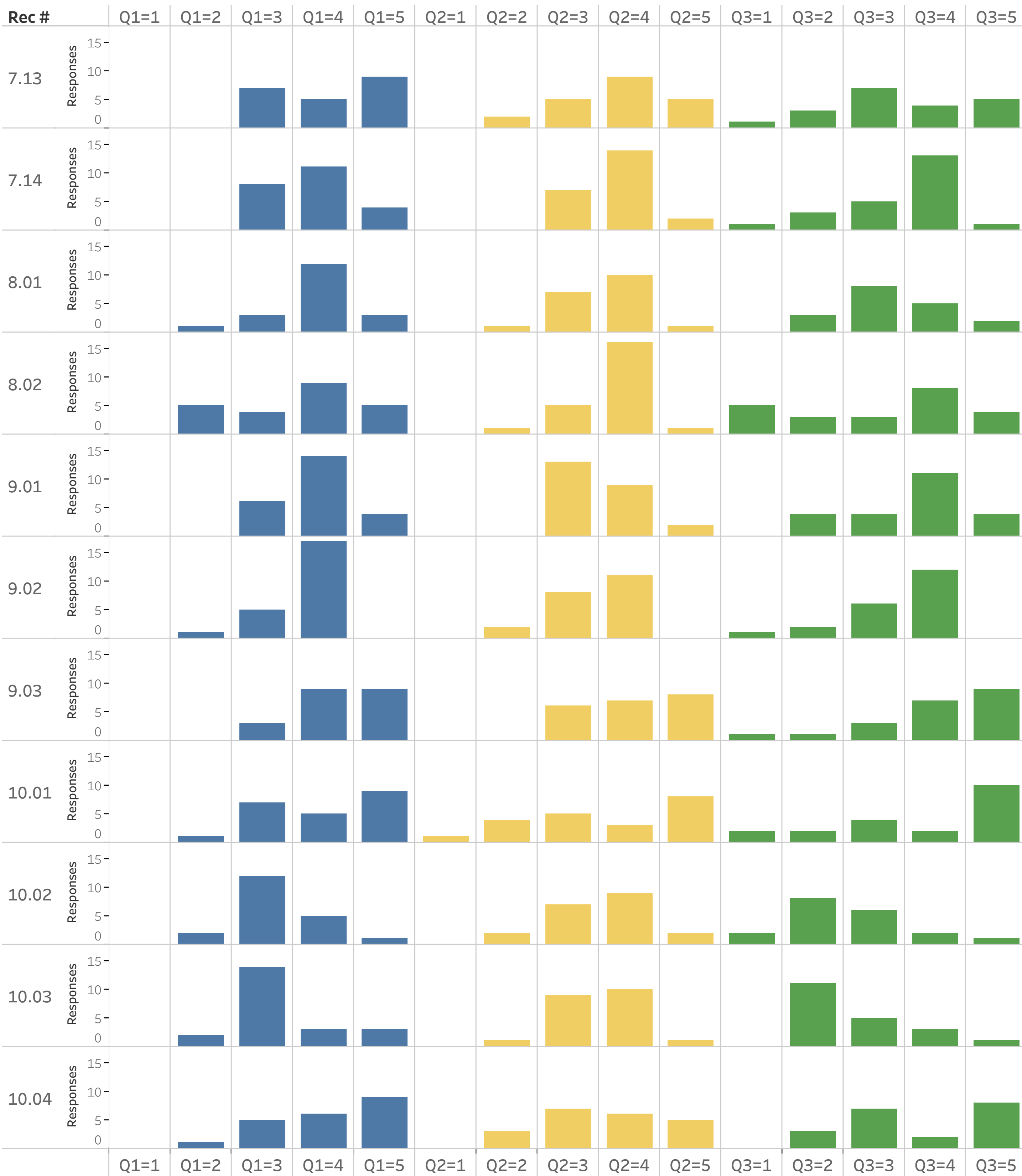
Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)



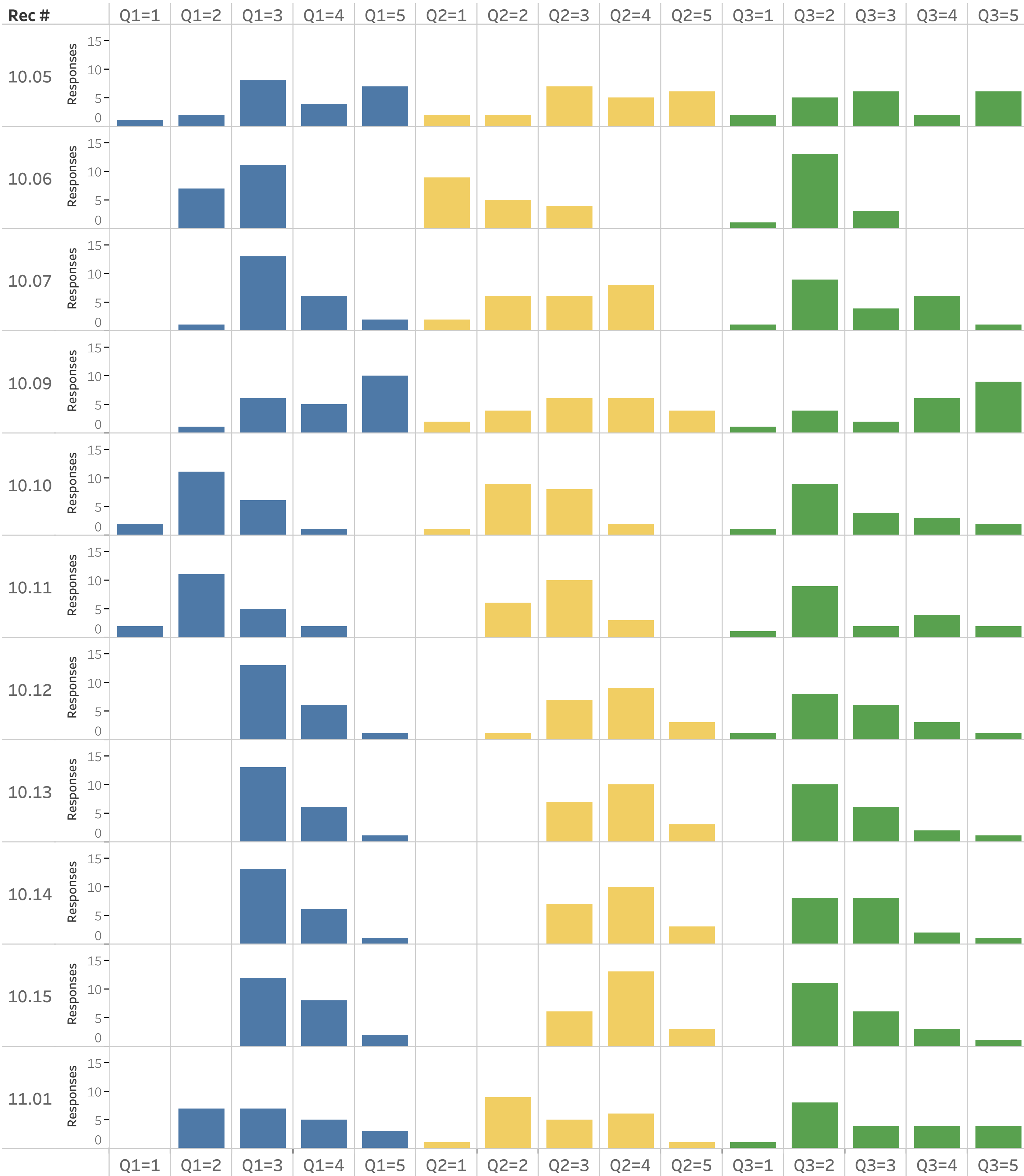
Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)



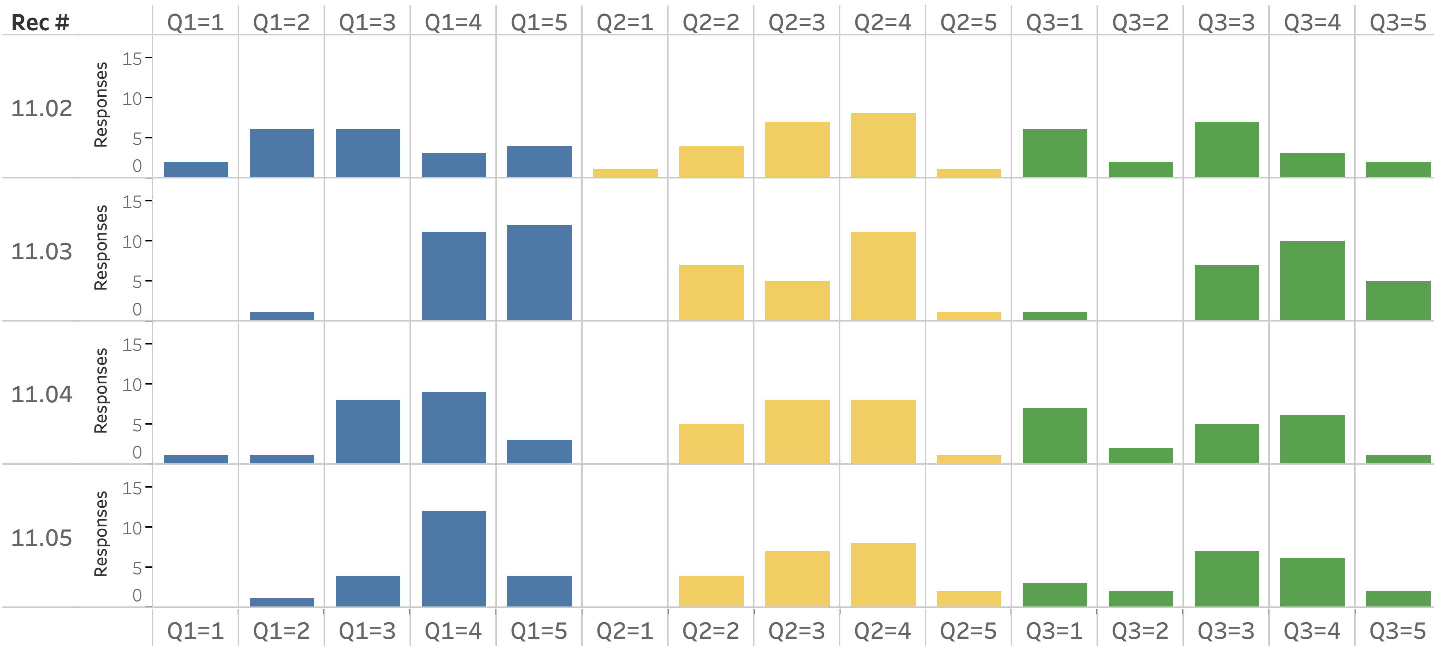
Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)



Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)



Policy Survey Responses to Questions #1 (Blue), #2 (Yellow), #3 (Green)



End of Attachment B